SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report
Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

June 2024

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

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EXECUTIVE SUMMARY

South Coast AQMD Rule 1148.1 – *Oil and Gas Production Wells* (Rule 1148.1) applies to approximately 330 onshore oil or gas well facilities that conduct operations including drilling, well completion, well rework, and well injection activities. Rule requirements reduce VOC emissions from the wellheads and the well cellars through inspection and maintenance, and control of produced gas emissions. The rule also establishes work practices and odor mitigation procedures. In response to concerns raised by Assembly Bill (AB) 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area and the 2022 Air Quality Management Plan Control Measure FUG-01: Improved Leak Detection and Repair, Proposed Amended Rule (PAR) 1148.1 will further reduce and control VOC emissions. PAR 1148.1 will: 1) add new definitions to further clarify the amendments being proposed, 2) require the use of enhanced leak detection technology, 3) require equipment that uses produced gas to meet specific NOx limits and to verify compliance via source tests, 4) require workover rigs to use Tier 4 Final diesel engines, 5) ban the use of odorants that are used to mask odors emanating from oil production sites, and 6) update signage requirements. Additional minor changes to rule language will be made for consistency and clarity.

CHAPTER 1: BACKGROUND

INTRODUCTION

Rule 1148.1 – *Oil and Gas Production Wells* requires operators of oil and gas wells to reduce emissions of volatile organic compounds (VOCs), toxic air contaminants (TAC) emissions and Total Organic Compounds (TOC) from the operation of wellheads, well cellars, and the handling of produced gas at oil and gas production facilities. Well activity occurs at multiple sites throughout the South Coast AQMD and may be found near residential communities as shown in Figure 1.1.

Figure 1.1 – Example of Urban Oil Well

Concerns have been raised by AB 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area about the need for additional, timely and reliable requirements to further control VOC emissions coming from oil and gas production facilities. In response, staff proposes to modify requirements in Rule 1148.1 to add the use of enhanced leak detection technology, require Tier 4 Final diesel engines in the use of workover rigs engaged in general maintenance activities, and source test requirements for stationary equipment that uses produced gas to verify emission limits. Staff also proposes to ban the use of odorants used to mask odors and update signage requirements. Additional definitions and minor changes to rule language are made for consistency and clarity.

REGULATORY BACKGROUND

Rule 1148.1 was adopted on March 5, 2004, to implement Control Measure FUG-05 of the 2003 AQMP by reducing VOC emissions from the wellheads and the well cellars located at oil and gas production facilities through increased inspection and maintenance, and control of produced gas emissions, with additional regulatory considerations when located within 100 meters to sensitive receptors. See Figure 1.2 for an example of wellheads inside a well cellar.

Figure 1.2 – Example of Wellheads Inside a Well Cellar

Rule 1148.1 was amended on September 4, 2015 to minimize environmental impacts on neighboring communities and sensitive receptors from ongoing operations, including well stimulation techniques such as hydraulic fracturing. Between 2010 and 2014, operations at an urban oil and gas production facility were the subject of numerous public complaints and received multiple Notices of Violations (NOV) from the South Coast AQMD. The amendment focused on improving work practices and established odor mitigation procedures.

AB 617 and Concerns with Oil and Gas Well Activities

In 2017, Governor Brown signed AB 617 (C. Garcia, Chapter 136, Statutes of 2017) to develop a new community-focused program to potentially reduce exposure to air pollution and preserve public health. AB 617 directed the California Air Resources Board (CARB) and all local air districts, including the South Coast AQMD, to enact measures to protect communities disproportionally impacted by air pollution. On September 27, 2018, CARB designated 10 communities across the state to implement community plans for the first year of the AB 617 program. Local air districts were tasked with developing and implementing community emissions reduction and community air monitoring plans in partnership with residents and community stakeholders. The Community Air Monitoring Plan (CAMP) includes actions to enhance the understanding of air pollution in the designated communities and to support effective implementation of the Community Emissions Reduction Plan (CERP). A CERP provides a blueprint for achieving air pollution emission and exposure reductions, addressing the community's highest air quality priorities. The CERP includes actions to reduce emissions and/or exposures in partnership with community stakeholders.

During their CERP development process, the WCWLB and SLA communities raised numerous concerns related to oil and gas well activity and current South Coast AQMD rules.

The CERP for WCWLB listed four main air quality priorities related to oil drilling and production. These priorities focused on:

- The need for near-facility air measurements and inspections to address leaks and odors from oil drilling and production;
- Fenceline air monitoring;
- Vapor recovery systems and leak detection technologies; and
- The use of lower or zero-emission equipment for on-site operations.

The CERP for SLA also listed multiple priorities related to oil drilling and production. These priorities focused on:

- Identification of potential elevated emissions through air measurement surveys around oil drilling sites;
- Determination of which oil well sites and activities may require additional monitoring;
- Explore limiting/eliminating odorant use;
- Explore requirements for lower emission or zero-emission equipment;
- Reduction emissions and exposure to oil and gas operations through rule amendments to the Rule 1148 Series;
- Incentive funding opportunities for best management practices and/or installation of emission reduction technologies at oil and gas facilities.

Note that some other community concerns have been addressed in the February 2023 amendment to *Rule 1148.2 – Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers* (Rule 1148.2) such as providing notifications for activities such as acidizing of water injection wells. In addition, Rule 1148.2 has requirements for mailers to be sent out to sensitive receptors within 1,500 feet of an oil and gas or injection well prior to the commencement of an acidizing event.

AFFECTED FACILITIES

Proposed Amended Rule 1148.1 affects any operator of an oil or gas production facility located within the jurisdiction of the South Coast AQMD and its operation and maintenance of wellheads, well cellars, and the handling of produced gas. There are approximately three hundred and thirty facilities potentially affected by this amendment.

PUBLIC PROCESS

The development of PAR 1148.1 was conducted through a public process. Four Working Group Meetings were held on: April 20, 2023, September 14, 2023, December 14, 2023, and April 11, 2024. In addition, staff participated in AB 617 meetings to notify and update stakeholders on the rule development process. Stakeholders include representatives from the community, environmental organizations, industry representatives, and government agencies. Staff also met individually with industry stakeholders and visited sites affected by the rule development process.

Working group meeting notices were provided to operators, suppliers and participants of AB 617 meetings that signed up for notifications of AB 617 updates or oil and gas well rule development. A Public Workshop meeting was held on February 1, 2024, where staff presented the proposed rule to the general public and stake holders, and received comments related to the proposal.

CHAPTER 2: BARCT ASSESSMENT

INTRODUCTION

As part of the rule development process, staff conducted a Best Available Retrofit Control Technology (BARCT) assessment of equipment subject to PAR 1148.1. The purpose of a BARCT assessment is to identify potential emission reductions from specific equipment and to establish an emission limit consistent with state law.

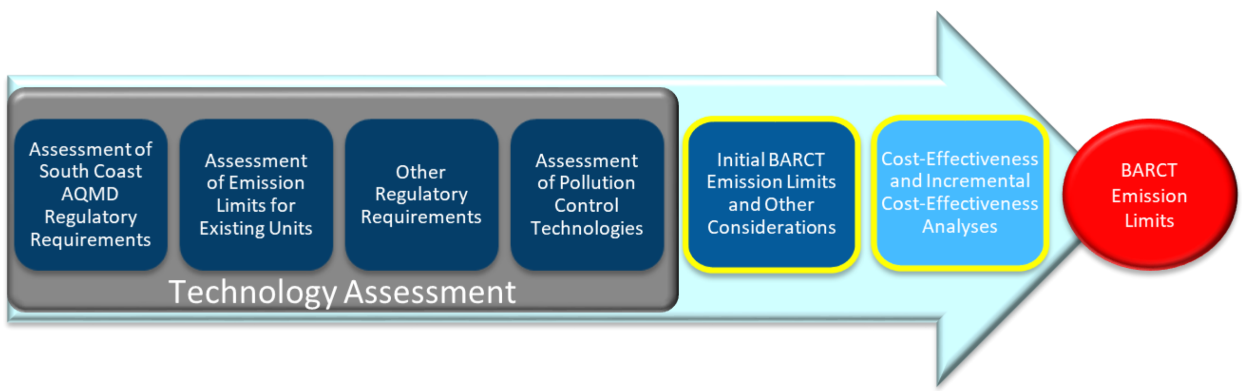
Under Health and Safety Code Section 40406, BARCT is defined as:

> "… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

The BARCT assessment for this rule development consisted of a multi-step analysis. The first four steps represent the technology assessment. First, staff evaluated current South Coast AQMD regulatory requirements with an applicability to this rule development. Second, staff then assessed emission limits for existing units. Third, staff next surveyed other air districts and agencies outside of the South Coast AQMD's jurisdiction to identify emission limits that exist for similar equipment. In the final step of the technology assessment, staff assessed pollution control technologies to determine what degree of reduction could be achievable for the affected sources. Based on the technology assessment, initial emission limits and other considerations were proposed.

Once initial emission limits have been proposed, staff then calculated the cost-effectiveness of the proposals. The calculations consider the cost to meet the initial BARCT emission limit and the emission reductions that would occur from implementing technology that could meet the initial BARCT emission limit. An incremental cost-effectiveness analysis is conducted if multiple cost-effective control technology options are identified. Options are compared to determine costs of emission reductions. Based on the evaluation of the information, BARCT emission limits are recommended. See Figure 2-1 below for a graphical representation of the BARCT assessment process.

Figure 2.1 – BARCT Assessment Process



BARCT ANALYSIS APPROACH

In this rulemaking effort, staff is considering the following proposals to be incorporated into the rule:

(1) Adding the use of enhanced monitoring and leak detection techniques
(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps
(3) Establishing emission limits for stationary gas turbines using produced gas for fuel
(4) Requiring electrification or the use of cleaner engines for workover rigs

(1) Adding the use of enhanced monitoring and leak detection techniques

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1(i)(1) requires the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to inspect components and equipment regulated by the rule. Typically, the analyzer used is a Toxic Vapor Analyzer (TVA) (See Figure 2.2). A TVA is capable of measuring a variety of organic vapors using flame ionization detection (FID) technology and it provides a concentration value of the organic vapor.

Figure 2.2 – Example of a Toxic Vapor Analyzer

Other South Coast AQMD Rules also require the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to conduct inspections including but not limited to: Rule 1149 – *Storage Tank and Pipeline Cleaning and Degassing*; Rule 1173 – *Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants*; Rule 1176 – *VOC Emissions from Wastewater Systems*; and Rule 1178 – *Further Reductions for VOC Emissions from Storage Tanks at Petroleum Facilities*.

In September 2023, Rule 1178 was amended to include optical gas imaging (OGI) inspections for equipment subject to the rule. In June 2024, Rule 463 was also amended to require OGI inspections.

- *Assessment of Emission Limits of Existing Units*

The use of OGI equipment does not have an emission limit relevant to this analysis. As such, no assessment of emission limits of existing units is required.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that the use of enhanced monitoring techniques utilizing OGI was limited.

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4409 – *Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities*, subsection 6.3, after June 30, 2024, requires that all leaks detected with the use of an OGI instrument shall be measured using U.S. EPA Reference Method 21 within two calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in the rule.[1]

Figure 2.3 – Example of an OGI camera

Under Colorado Air Quality Control Commission Regulation Number 7 – *Control of Emissions from Oil and Gas Emissions Operations*, the use of an OGI camera can be utilized as part of an approved leak detection and repair plan.[2] Leak detection thresholds are quantified using a TVA or equivalent device.

- *Assessment of Pollution Control Technologies*

OGI equipment does not control pollution directly but is a tool that can be used to identify emissions. As such, no assessment of pollution control technology is required for adding the use of enhanced monitoring and leak detection techniques. However, a discussion on current enhanced monitoring and leak detection technologies is included.

<u>Optical Gas Imaging</u>

An optical gas imaging camera uses infrared technology capable of visualizing vapors. OGI cameras have different detectors capable of visualizing a variety of gas wavelengths. VOC wavelengths are in the 3.2-3.4 micrometer waveband.

Figure 2.4 – OGI Camera Imaging

The cameras are widely used as a screening tool for leak detection purposes and have continuous monitoring capability.

[1] San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4409 – *Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities*, subsection 6.3: https://ww2.valleyair.org/media/z11dynbx/rule-4409.pdf, page 4409-21, accessed on 11/01/2023.

[2] Colorado Air Quality Control Commission Regulation Number 7 – *Control of Emissions from Oil and Gas Emissions Operations*: https://drive.google.com/file/d/1P6pRmNYx5KwEK6qDReYFL11-K-URI33J/view, page 36, accessed on 11/01/2023.

Handheld OGI cameras are used widely by leak detection service providers as well as facilities for periodic monitoring.

Open Path Sensors

Open path detection devices emit beams that detect VOCs (See Figure 2.5). For VOC to be detected with an open path device, the VOCs must contact the beam. Open path detection devices can detect gas concentrations in the parts per billion range and from distances as far as 300 meters away from a source, with some models advertised as having a range of 1,000 meters. One open path device can cover multiple paths. Open path devices can detect small concentrations of VOC in the parts per billion by volume (ppbv) range and can also speciate VOC. A significant limitation to leak detection of these devices is the requirement for VOCs to contact the emitted beam. This provides a chance for VOCs to go undetected if travelling on a path that does not intercept the beam. Another drawback to open path detection is the dilution factor. VOCs originating from a tank may need to travel hundreds of feet before contacting the emitted beam. The concentration of VOC may dilute so significantly that VOCs are undetectable by the time the VOCs reach the emitted beam.

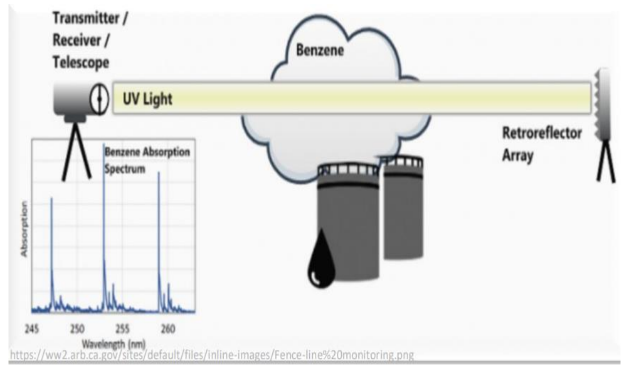


Figure 2.5 – Example of Open Path Technology

Fixed Gas Sensors

Fixed gas sensors have the capability to continuously monitor for VOC emissions and are installed as fixed applications (See Figure 2.6). Concentrations of VOC detected with fixed gas sensors are in the parts per million by volume (ppmv) range depending on the sensor and have a maximum detection range of about 50-100 ppmv. Like open path devices, gas sensors can only detect emissions when VOCs contact the fixed sensor. Leaks from a source must be significant to be detected by a fixed gas sensor due to the dilution factor. According to one supplier, it is estimated that a leak with a concentration of 72,000 ppmv is detectable by a gas sensor 100 feet away. A leak with a concentration of 18,000 ppmv is detectable by a gas sensor 50 feet away.

Figure 2.6 – Example of a Fixed Gas Sensor

(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1 does not have any emission limits for engines operated at facilities subject to this rule. However, other South Coast AQMD rules do regulate internal combustion engines. South Coast AQMD Rules 1110.2 – *Emissions from Gaseous- and Liquid-Fueled Engines* and

1470 – *Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines* regulate emissions from internal combustion engines that are rated greater than 50 bhp. In addition, stationary engines that are greater than 50 bhp are required to be permitted by the South Coast AQMD. Some engines, however, that are less than 50 bhp but are operated by facilities subject to the South Coast AQMD Regional Clean Air Incentives Market (RECLAIM) program are also subject to permitting requirements. Portable engines that are greater than 50 bhp are required to be either registered by the California Air Resources Board (CARB) through their Portable Equipment Registration Program (PERP) or permitted by the South Coast AQMD.

- *Assessment of Emission Limits of Existing Units*

Figure 2.7 – Example of an ICE

During the rule development process, staff visited multiple sites where internal combustion engines were observed to be operating wellhead pumps (See Figure 2.7). The sites were not part of the RECLAIM program. In general, these engines were rated under 50 bhp and were powered by produced gas from the individual sites. The engines were not observed to have any emission controls on their exhaust. As long as the supply of produced gas was available or as necessary, the engines were operated continuously 24 hours a day, 7 days a week. Because the observed engines were rated at less than 50 bhp, Rules 1110.2 and 1470 do not apply. Thus, the engines used to operate wellhead pumps generally do not have an emission limit unless the engine is rated greater than 50 bhp.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, engines are not included in their respective regulations. However, in their suite of rules, other regulatory agencies do regulate emissions from stationary internal combustion engines such as: BAAQMD Regulation 9 – *Inorganic Gaseous Pollutants*, Rule 8 – *Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines* and SJVAPCD Rule 4702 – *Internal Combustion Engines.*

- *Assessment of Pollution Control Technologies*

Application of Nonselective Catalytic Reduction Technology

During site visits, staff noted that the internal combustion engines observed were engines that are classified as rich-burn engines. Rich-burn engines operate at a higher concentration of fuel to air in its combustion chamber compared to lean-burn engines which operate at a higher concentration of air to fuel in its combustion chamber. With a higher concentration of fuel to air, rich-burn engines respond to varying loads more effectively compared to lean-burn engines. On oil field and gas production sites, the supply of produced gas to an engine can vary making the rich-burn engine one of choice and necessity.

Although no exhaust emission controls were observed on engines used to operate wellhead pumps, there exists commercially available air pollution control equipment that can be installed on rich-burn engines such that if operated properly can achieve emission reduction compliant to the NOx emission limit established in Rule 1110.2.

Nonselective Catalytic Reduction (NSCR) technology is applicable to all rich-burn engines and is a common control method for rich-burn engines (See Figure 2.8). The first wide scale application of NSCR technology occurred in the mid- to late-1970s, when 3-way NSCR catalysts were applied to motor vehicles with gasoline engines. Since then, this control method has found widespread use on stationary engines. Improved NSCR catalysts, called 3-way catalysts because CO, VOC, and NOx are simultaneously controlled, have been commercially available for stationary engines for over 20 years.

Figure 2.8 – Example of an NSCR Device

The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The 3-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric.

Removal efficiencies for a 3-way catalyst are greater than 90% for NOx, greater than 80% for CO, and greater than 50% for VOC. Greater efficiencies, below 10 parts per million NOx, are possible through use of an improved catalyst containing a greater concentration of active catalyst materials, use of a larger catalyst to increase residence time, or through use of a more precise air/fuel ratio controller.

NSCR catalysts are subject to masking, thermal sintering, and chemical poisoning. In addition, NSCR is not effective in reducing NOx if the CO and VOC concentrations are too low. NSCR is also not effective in reducing NOx if significant concentrations of oxygen are present. In this latter case, the CO and VOC in the exhaust will preferentially react with oxygen instead of the NOx. For this reason, NSCR is an effective NOx control method only for rich-burn engines.

When applying NSCR to an engine, care must be taken to ensure that the sulfur content of the fuel gas is not excessive. The sulfur content of pipeline-quality natural gas and LPG is very low, but some oil field gases and waste gases can contain high concentrations. Sulfur tends to collect on the catalyst, which causes deactivation. This is generally not a permanent condition and can be reversed by introducing higher temperature exhaust into the catalyst or simply by heating the catalyst. Even if deactivation is not a problem, the water content of the fuel gas must be limited when significant amounts of sulfur are present to avoid deterioration and degradation of the catalyst from sulfuric acid vapor.

In cases where an engine operates at idle for extended periods or is cyclically operated, attaining and maintaining the proper temperature may be difficult. In such cases, the catalyst system can be designed to maintain the proper temperature, or the catalyst can use materials that achieve high efficiencies at lower temperatures. For some cyclically operated engines, these design changes may be as simple as thermally insulating the exhaust pipe and catalyst. Most of these limitations can be eliminated or minimized by proper design and maintenance.

Electrification of All Engines

During site visits, staff observed that most wellhead pumps are electrically driven. However, on a few sites, some wellhead pumps were being powered by engines fueled by produced gas. Staff noted that on these few sites, the produced gas could not be routed offsite for further processing or collection. In order to maintain operation of the site, the operator could either vent the produced gas to the atmosphere, install a combustion device to flare it, install a boiler or heater to consume it, or utilize an internal combustion engine or a stationary turbine to produce power to run a wellhead pump. In the past, another option included potentially reinjecting the produced gas back into the oil formation; however, staff has learned that other regulatory agencies such as the City of Los Angeles Zoning Administrator severely restrict this practice and it is no longer common.

(3) Establishing emission limits for stationary gas turbines using produced gas for fuel

- *Assessment of Current South Coast AQMD Regulatory Requirements*

During the rule development process, staff visited multiple sites where stationary gas turbines were operated using process gas as their fuel source. Currently, Rule 1148.1 does not have an emission limit for turbines operated at facilities subject to this rule. However, for turbines that are rated at 0.3 MW and larger, South Coast AQMD Rule 1134 – *Emissions of Oxides of Nitrogen from Stationary Gas Turbines* applies.

- *Assessment of Emission Limits of Existing Units*

Rule 1134 limits NOx emissions from stationary gas turbines that are fueled by produced gas to 9 ppmv at 15% O_2 on a dry basis. For engines rated at less than 0.3 MW, there is currently no emission limit set by the South Coast AQMD.

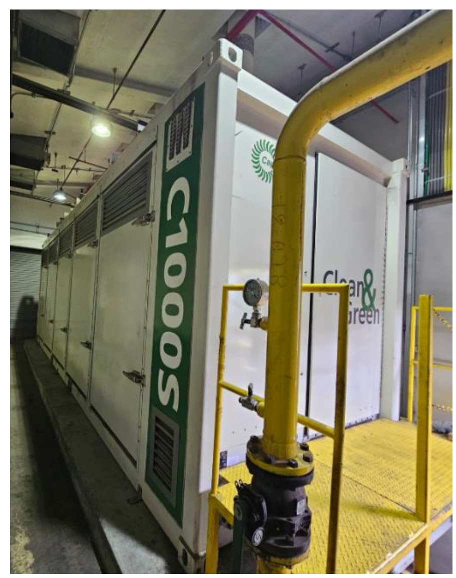


Figure 2.9 – Example of a Stationary Gas Turbine

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, stationary gas turbines are not included in their respective regulation. However, in their suite of rules, other regulatory agencies do regulate the emissions from stationary gas turbines engines such as: BAAQMD Regulation 9 – *Inorganic*

Gaseous Pollutants, Rule 9 – *Nitrogen Oxides Stationary Gas Turbines* and SJVAPCD Rule 4703 – *Stationary Gas Turbines*. These rules also exempt smaller turbines such as those used at oil and gas well production sites.

The CARB Distributed Generation Certification Regulation is available to smaller gas turbines that are exempt from air district permitting requirements. These units must demonstrate that they meet or exceed the following emission standards:

Table 2.1: DG Emission Standards

Pollutant	Emission Standard (lb/MW-hr)
NOx	0.07
CO	0.10
VOCs	0.02

- *Assessment of Pollution Control Technologies*

To control NOx emissions, Selective Catalytic Reduction (SCR) technology is often used. SCR is a commercially available air pollution control system used to reduce NOx emissions from stationary gas turbines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Dry Low NOx controls NOx by combusting gas at lower temperatures using a lean premixed combustion. An advanced control system in also utilized. Low NOx levels are achieved as the process requires less fuel and air resulting in lower combustion temperatures.

(4) Requiring electrification or the use of cleaner engines for workover rigs

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, the electrification or the use of cleaner engines for workover rigs is not required by Rule 1148.1. Other South Coast AQMD rules do not mandate the use of electrified or cleaner engines. However, Rule 1148.2 requires the operator of a workover rig where the engine does not meet a minimum Tier 4 – Final emissions standards of Title 40 of the Code of Federal Regulations Part 1039 Subpart B, Section 1039.101, Table 1 and the engine is not powered by a non-combustion source, to notify the Executive Officer no more than 10 calendar days and no less than 24 hours prior to the use of the workover rig on either an onshore oil or gas well, or an injection well. This engine standard shall also apply to any engine that connects to, and assists, the workover rig with any well activity.

- *Assessment of Emission Limits of Existing Units*

Typically, workover rigs use engines that are considered to be off-road compression-ignition diesel engines and are registered through CARB's PERP. Depending on the age and the rated bhp of the engine, an engine is assigned to a Tier category. Based on the tier level, emission limits vary. For example, a 2008 engine rated between 75 – 100 bhp falls under the Tier 3 category and it has a NOx emission limit of 3.5 g/bhp-hr (~ 234 ppmv at 15% O_2). In comparison, a 2015 engine rated similarly falls under the Tier 4 Final category and it has a NOx emission limit of 0.14 g/bhp-hr (~ 9 ppmv at 15% O_2). It should be noted that engines which are integrated with the propulsion of the rig itself is not included in CARB's PERP.

Figure 2.10 – A Workover Rig in Operation

- *Other Regulatory Requirements*

U.S. EPA has developed Tier 4 standards for nonroad diesel engines to reduce emissions. Exhaust emissions from Tier 4 engines decrease emissions from older engines by more than 90%.[3] The Tier 4 standards took effect for new engines beginning in 2008 and were fully phased in for most diesel engines by 2014. Thus, new engines manufactured after 2008 are required to meet the applicable standard effective when the engine is built. Staff has noted that engines used on workover rigs range between 175 ≤ hp < 750 and widely range in age. Staff has observed during site visits that only some engines used on workover rigs are currently required to meet Tier 4 standards.

The Tier 4 emission standards are provided in the following table.

[3] U.S. EPA, Summary and Analysis of Comments: Control of Emissions from Nonroad Diesel Engines, May 2004: https://nepis.epa.gov/Exe/ZyPDF.cgi/P10003DS.PDF?Dockey=P10003DS.PDF, accessed on 11/2/2023

Table 2.2 – Final Emission Standards in grams per horsepower-hour (g/hp-hr)

Rated Power	First Year that Standards Apply	PM	NOx
hp < 25	2008	0.30	-
25 ≤ hp < 75	2013	0.02	3.5*
75 ≤ hp 175	2012-2013	0.01	0.30
175 ≤ hp < 750	2011-2013	0.01	0.30
hp ≥ 750	2011-2014 2015	0.075 0.02/0.03**	2.6/0.50† 050††

* The 3.5 g/hp-hr standard includes both NOx and nonmethane hydrocarbons
† The 0.05 g/hp-hr standard applies to gensets over 1200 hp
** The 0.02 g/hp-hr standard applies to gensets; the 0.03 g/hp-hr standard applies to other engines
†† Applies to all gensets only.

- *Assessment of Pollution Control Technologies*

SCR Technology

To achieve Tier 4 final NOx emission levels, engine manufacturers will use small-scaled SCR units on the exhaust of these engines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Electrification of Engines Used for Workover Rigs

Staff observed the use of an electrified workover rig at two different sites and is aware of another electrified workover rig that had once been installed and operated at another site. At the two sites where there was an electrified rig, staff noted that the units were not capable of leaving the site and were confined to move on a fixed rail system within the facility. In addition, each site had been retrofitted with a robust electrical substation to meet the electrical demand required by a workover rig. The fixed rail system would also be especially challenging for oil and gas well sites that are difficult to access due to terrain and location. See Figure 2.11 for photos on an electrically powered drilling/workover rig.

Figure 2.11 – Photo on left shows electrified drilling/workover rig and photo on right shows inside view. Note that this drilling/workover rig is on a rail and can only be used at this specific site

CHAPTER 3: PROPOSED AMENDMENTS TO RULE 1148.1

INTRODUCTION

Staff participated in multiple meetings with WCWLB and SLA community residents, acknowledged the CERP, conducted multiple site visits to oil and gas production sites, conducted a BARCT assessment, and presented our findings in a public process. The following proposals address the concerns raised in these communities.

PROPOSED AMENDMENTS TO RULE 1148.1

Subdivision (c) – Definitions

The definitions listed below are being revised or added due to the proposed amendments to Rule 1148.1:

- **COMPONENT** – The definition is updated to include the wellhead and stuffing box as recognized components.

- **ENGINE** – During the rule development process, staff noted that produced gas was being utilized to power engines used to operate wellheads. Staff has added this definition as part of introducing emission limits onto engines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1110.2 for development of this definition.

- **FUEL CELL** – The definition is added to recognize the technology as an alternate to engines. U.S. EPA describes fuel cells as follows. A fuel cell is an electrochemical device similar to a battery. While both batteries and fuel cells generate power through an internal chemical reaction, a fuel cell differs from a battery in that it uses an external supply that continuously replenishes the reactants in the fuel cell. A battery, on the other hand, has a fixed internal supply of reactants. The fuel cell can supply power continuously as long as the reactants are replenished, while the battery can only generate limited power before it must be recharged or replaced.[4]

- **GAS HANDLING** – Staff discussed the intent of gas handling operations within the Applicability section of the rule and discovered a potential misunderstanding of using the term "processed gas" instead of "produced gas." Staff updated rule language to state "produced gas" in the first sentence of the Applicability section and created a definition for "gas handling" to further clarify the intent of this rule.

- **NEUTRALIZING AGENTS** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities have expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public. Staff is making a distinction between neutralizing agents and odorants, which are specifically designed to mask an odor.

[4] U.S. EPA Auxiliary and Supplemental Power Fact Sheet: Fuel Cells: https://www.epa.gov/sites/default/files/2019-08/documents/fuel_cells_fact_sheet_p1004xfm.pdf, accessed on 6/14/2023

- **ODORANT** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities have expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public.

- **OPTICAL GAS IMAGING DEVICE** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **STATIONARY GAS TURBINE** – During the rule development process, staff noted that produced gas was being utilized to power stationary gas turbines that produce electricity to either power the site or supply the local electrical power grid. Staff has added this definition as part of introducing emission limits onto turbines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1134 for development of this definition.

- **TIER 4 FINAL ENGINE** – U.S. EPA finalized Tier 4 standards for nonroad diesel engines that reduce emissions by integrating engine and fuel controls as a system. Exhaust emissions of PM and NOx from these engines will decrease by more than 90%. These standards are achieved through the use of advanced exhaust gas after-treatment technologies such as urea-selective catalyst reduction (SCR) catalysts for NOx control, and diesel particulate filters (DPFs) for PM control. The use of ultra-low sulfur diesel (ULSD) fuel with a maximum sulfur content of 15 ppmv or less is also generally required.

- **VISIBLE VAPORS** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **WORKOVER RIG** – Staff has added this definition to describe what a workover rig is. Staff developed this definition by researching various oil field industry websites that listed workover rigs, and from first-hand observations of workover rigs used in the local oil field production facilities.

Subdivision (d) – Requirements

The requirements listed below are being revised or added due to the proposed amendments to Rule 1148.1.

- Paragraphs (d)(7) and (d)(9) – The word "business" was removed from these paragraphs for consistency. The oil and gas production facilities operate 24 hours a day and 7 days a week. Therefore, there is no need to distinguish a business day from a regular day.

- Paragraph (d)(13) – During the amendment to Rule 1148.2 – *Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers*, concerns were raised about signs installed at oil field and production sites. AB 617 stakeholders requested that instructions be provided on how to make odor complaints and electronically access information on well activities. Staff referenced South Coast AQMD Rule 1460 –*Control of Particulate Emissions from Metal Recycling and Shredding Operations* for development of this requirement. Figure 3.1 shows a typical sign for an oil and gas facility.

Figure 3.1 - Example of Signage Prior to Amendment

- Paragraph (d)(14) – Staff has added this requirement as part of introducing enhanced monitoring technology using an OGI camera as part of the inspection process.

- Paragraph (d)(15) – Staff has added a NOx emission limit to engines that are powered by produced gas. During site visits, staff discovered engines being used to process produced gas from oil field sites. These engines were observed in the operation of wellheads and similar production equipment.

  Generally, produced gas can be collected and routed from an oil field to another location offsite to be further processed into a usable stream. For example, some produced gas can be sent to supply the Southern California Gas Company or similar company. Alternatively, produced gas can be collected from an oil field and used onsite to power combustion equipment such as a stationary gas turbine, an engine. If the gas cannot be sent offsite or used to power combustion equipment, then it is vented to a flare.

  In the case of engines using produced gas, staff discovered that these engines were typically rated at less than 50 bhp. By using engines that are rated less than 50 bhp, an engine is not subject to the emission limits established in Rule 1110.2. Rule 1110.2 applies only to engines rated greater than 50 bhp. In addition, the South Coast AQMD does not require a permit to operate for an engine rated less than 50 bhp unless the engine is located at a facility subject to the South Coast AQMD RECLAIM program. Rule 1110.2 may be amended in future rulemaking activity to include engines that are rated at less than 50 bhp. However, since these engines are currently operated at oil and gas production facilities, staff has included them under this rule to address air quality concerns and potential health impacts to the community.

Staff is concerned that this type of engine is an uncontrolled source of emissions. Staff visited sites where these engines were observed in operation and noted that these engines can operate continuously 24 hours a day, 7 days a week based on produced gas supply and/or electrical demand. Upon observing these engines, staff did not see any emission control devices on them. Staff also has observed that multiple engines can operate within close proximity to each other where although a single engine may be rated at less than 50 bhp, the aggregate horsepower of all of the engines on the site exceeds 50 bhp. In addition, staff has observed that some of these engines are located within less than 1000 feet of sensitive receptors such as residences and other dwellings.

During the third working group meeting that was held on December 14, 2023, staff received a comment inquiring if the produced gas could be reinjected back into the ground. Staff researched the inquiry and held a meeting with an LA City Planning employee and discovered that reinjecting gas back into the ground is discouraged due to safety concerns of having gas stored below residential neighborhoods. Additionally, LA City prefers to have the produced gas used in microturbines that meet certain emission standards. Staff also recognizes that CalGEM already regulates injection wells, including underground gas storage.

To address concerns over these engines, staff is proposing that engines meet the NOx emission limit applicable to engines regulated by Rule 1110.2 irrespective of rating. Currently, the NOx emission limit for Rule 1110.2 engines is established at 11 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(16) – Staff has added a NOx emission limit to stationary turbines that are powered by produced gas. During site visits, staff observed stationary turbines being used to process produced gas from oil field sites generating electricity that was either being used onsite or was exported to the electrical power grid. For stationary turbines rated greater than 0.3 MW, Rule 1134 applies; however, for units rated less than 0.3 MW, no emission limits are applicable. Staff has generally observed microturbines that are rated at 65 kW (0.065 MW) at various oil and gas production sites with some larger ones rated at 200 kW (0.2 MW).

  To address concerns over turbines that are not subject to Rule 1134, staff is proposing that all stationary turbines meet the NOx emission limit applicable to stationary turbines as regulated by Rule 1134 irrespective of rating. Staff considers that the amount of microturbines installed and operated at oil and gas production sites to be a small number. Thus, rather than amend Rule 1134, staff is including this subset of turbines in this rule. Currently, the NOx emission limit for Rule 1134 turbines fueled by produced gas engines is established at 9 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(17) – Staff is proposing that workover rigs used at oil and gas well sites be equipped with at least a Tier 4 Final engine. Based on AB 617 community concerns over emissions from diesel workover rigs, staff conducted site visits and also researched the potential emission reductions and feasibility of requiring electrified workover rigs. Part of the research included conducting a cost-effectiveness analysis. The results indicated that electrifying the workover rigs would exceed the cost-effectiveness threshold and take many more years to implement due to lack of infrastructure that would be needed.

  To address concerns over emissions from workover rigs, staff is proposing requiring all workover rigs to meet Tier 4 Final standards. While conducting research on this proposal staff found that the emission reductions on a Tier 4 Final engine are significant compared to Tier 2 level engines and this requirement was found to be cost-effective. Staff is proposing a three-year implementation period from the date of this rule amendment to either upgrade or replace their fleet of workover rigs. In addition, staff has found that some oil and gas operators have already upgraded part of their workover fleet to meet Tier 4 Final engine standards.

- Paragraph (d)(18) – Staff is proposing to ban the use of odorants, specifically odorants that are used to mask another chemical substance's smell. AB 617 community stakeholders have expressed concerns about the use of odorants and the potential exposure to unknown chemicals.

  Staff researched and found that some oil and gas production site operators are using odorants with strong fruit fragrances like guava or cherry. These operators have attempted to mask petroleum and oily-type odors with these odorants but it has led to several public nuisance violations with complaints of rotten fruit-type odors mixed with petroleum odors. Some complainants described having headaches. Mistrust has been created among community members due to the lack of knowledge about an odorant's chemicals and the substance that is being masked with the odorant. Odorants are generally composed of hydrocarbons such as alcohols and glycols but may also contain phenols or aromatics. These chemicals contribute to ozone formation and public nuisance complaints. They may also have health impacts depending on the type and quantity of the odorant substance.

  Paragraph (d)(19) - Staff recognizes that oil and gas operators may use neutralizing agents as an alternative to odorants for maintenance of their wells, including during the removal of well tubing as the well tubing may have its own odors. Neutralizing agents work to "knock out" or eliminate the odors, as opposed to masking the odors. Staff has proposed to allow the continued use of neutralizing agents that do not contain any toxics listed in Rule 1401 in quantities greater than 0.1% by weight. Staff also suggests that neutralizing agents be applied in liquid or droplet form and should not be atomized. If a neutralizing agent were atomized into the air, these chemicals may create odors. Staff has added definitions to clarify the differences in this requirement by adding the word ‘odorant’ and the word ‘neutralizing agent’ to the list of definitions.

It should be noted that this requirement does not affect the use of mercaptans or other chemicals that are purposefully injected into specific gas lines for safety purposes such as for detecting a gas leak in gas lines that are used, for example, in sales.

- Paragraph (d)(20) – Staff is proposing to require operators to submit a notification within twenty-four hours of discovering a leak greater than 25,000 ppmv VOC. Notifications were requested by community stakeholders that are interested in knowing when a leak has been found so that they can choose their next course of action.

  Operators will report leaks using the existing portal that is currently being used to submit notifications under Rule 1148.2. Interested parties that have signed up to receive Rule 1148.2 notifications will also receive notifications of reported leaks. The proposed data to be submitted will include facility information, leak concentration, date of discovery, and status of any repairs.

Subdivision (e) – Operator Inspection Requirements

- Paragraph (e)(6) – Staff has added an enhanced leak detection requirement using an OGI camera. The requirement has been modeled after the OGI requirement found in SJVAPCD Rule 4409. Comparing the use of an OGI camera with the use of a TVA, staff recognizes differences between the two applications. The OGI camera is expected to be used as a screening tool. With its current technological capabilities, an OGI camera cannot quantify an emission concentration whereas a TVA can report an emission in a concentration value. However, an OGI camera can scan more components quicker than a TVA, which can only inspect one component at a time. Used together, this technology is expected to give an operator the ability to identify leaks faster and to repair them sooner, compared with not using both in unison.

  Staff has added two options that operators can choose from when conducting their monthly OGI inspections and repairs under (e)(6)(B)(ii). If only using an OGI camera and quantification through use of a TVA is not initially made, operators will be required to repair any discovered leaks within twenty-four hours of discovery. Additionally, if any leak cannot be repaired within twenty-four hours, then the operator will be required to quantify the leak within forty-eight hours of leak discovery and to follow the Repair Period Table in Rule 1173. Note the repair period timing pursuant to Rule 1173 starts once quantification is made and the concentration of the leak is known.

  If using both an OGI camera and an appropriate analyzer, operators will be required to repair any discovered quantified leaks within the time allowed pursuant to the Repair Period Table in Rule 1173. In either option where quantification is needed, an appropriate analyzer that complies with paragraph (j)(1) shall be used. The intent of these two options is to give operators flexibility in conducting their monthly inspections. Staff recognizes that operators may not have ready access to a TVA; so, if an operator uses an OGI camera, identifies a leak, and repairs the leak below an OGI visible threshold, rather than wait for a TVA, then staff encourages a repair sooner than later.

Subdivision (i) – Testing Requirements

New subdivision (i) was added to demonstrate compliance with emission limits proposed in the amendment to the rule.

- Paragraph (i)(1) – Staff added a source testing requirement for engines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Prior to this amendment, many engines that fell under this category were rated under 50 bhp and no testing requirement was in place. Although these engines may be considered small, they can operate 24 hours a day, 7 days a week and cumulatively, the amount of emissions can be significant.

- Paragraph (i)(2) – Staff added a source testing requirement for stationary turbines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Although this provision is identical to the provision in paragraph (i)(1), it is included to distinguish turbines from engines. Specifically, an exemption from source testing is provided in paragraph (k)(5) if the turbine is certified through CARB's Distributed Generation program. No similar program is available for engines using produced gas.

Subdivision (j) – Test Methods

- Paragraph (j)(6) – Since emission limits for equipment have been included in this amendment, staff is adding that any source testing be completed per South Coast AQMD Method 100.1.

Subdivision (k) – Exemptions

- Paragraph (k)(5) – Staff added an exemption for a stationary turbine that has been certified by CARB Distributed Generation Certification program such that no source test of the engine shall be required. For engines that have not been certified as such, they will be required to demonstrate compliance via a periodic source test.

Other Revisions

- Since the 2015 Amendment to the rule, the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) has been replaced by the California Geologic Energy Management (GEM) Division. Reference to DOGGR has been replaced with GEM.

- The name of the agency such as AQMD or District has been replaced by the South Coast AQMD.

- Staff updated references within the rule to account for amendments and deleted obsolete wording and provisions.

- Staff considered revisions to paragraph (d)(8) but believes that the current language allows flexibility to address leaks from equipment associated with well heads and well cellars. For example, produced gas from a tank that has been blocked-in but contains inventory from oil and gas field production activities shall be routed to a system handling gas for fuel, sale, or underground injection or to a control device so as to avoid leaks.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

Impact assessments were conducted as part of PAR 1148.1 rule development to assess the environmental and socioeconomic implications of PAR 1148.1. These impact assessments include emission reduction calculations, cost-effectiveness and incremental cost-effectiveness analyses, a socioeconomic assessment, and a California Environmental Quality Act (CEQA) analysis. Staff prepared draft findings and a comparative analysis pursuant to Health and Safety Code Sections 40727 and 40727.2, respectively.

EMISSION REDUCTIONS

PAR 1148.1 will establish more stringent control and monitoring requirements at oil and gas production sites that will result in emission reductions.

OGI Monitoring

Staff is proposing the monthly use of OGI as a tool to find leaks from equipment regulated by this rule. By using OGI, leaks can be discovered and repaired sooner than through current inspection frequency and technique. Emission reductions from this proposal were calculated based on estimated baseline emissions and assumed one major leak per year from 10% of the 330 affected facilities. Staff used a leak rate of 200 lbs/day of VOC for each assumed major leak rate. This assumed leak rate is 98% smaller than the leak rate used in Rule 1178 but is expected to be consistent with the type of facilities regulated by this rule. Rule 1178 estimated approximately 8,000 lbs/day of emission losses based on U.S. EPA's 2016 Control Technology Guidelines for Oil and Gas Industry.[5]

Based on the current quarterly inspection frequency, staff assumes that an undiscovered leak occurs at a midpoint between inspections of 45 days. If the inspection frequency is increased to monthly, then staff assumes that an undiscovered leak occurs at a midpoint of 15 days. Comparing the current quarterly inspection frequency using the TVA to the proposed monthly frequency using OGI equipment, staff predicts that a potential leak may be discovered and repaired approximately 30 days sooner, a difference between 45 and 15 days.

To establish a baseline rate of potential emission, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- 45 days before a leak is identified

[5] South Coast AQMD Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1178/par-1178-draft-staff-report--final.pdf, page 4-2, accessed on 9/19/2023

- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lb) = 0.40 ton VOC/day
- Using these assumptions, a potential baseline of 0.40 ton per day of VOC is attributable to Rule 1148.1 related equipment.

With OGI monthly inspections, staff anticipates a reduction in VOC emissions compared to the baseline. To determine the reduction, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- Discovery of a leak 30 days sooner
- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (30 days) x (1 yr/365 day) x (1 ton/2000 lbs) = 0.27 ton VOC/day
- Using these assumptions, a potential reduction of 0.27 ton per day of VOC is attributable to OGI monthly inspections.

Fenceline Monitoring

<u>Stationary Gas Sensors</u>

Staff researched different types of fenceline monitoring systems and found that several oil and gas facilities had stationary gas sensors installed, primarily as a trial run for data collection. Staff found that that stationary gas sensors detect the targeted gas/emission such as VOCs once it makes contact with its sensor. During the research of fenceline monitors staff found that the number of sensors needed at each site varied depending on the size and terrain.

To determine potential emission reductions through fenceline monitoring using stationary gas sensors, staff used a similar approach to that used for OGI monitoring. In this case, since stationary monitors operate continuously, the emission reduction is credited as saving 45 days of undiscovered emissions. To quantify the reduction, staff performed the following calculation:

- One leak per year from 10% of 330 affected facilities
- A leak rate of 200 lbs/day of VOC
- 45 days of a leak that was identified
- Calculation – (1 leak/yr) x (33 facilities) x (200 lbs VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lbs) = 0.40 ton VOC/day
- Using these assumptions, a potential reduction of 0.40 ton per day of VOC is attributable to stationary gas sensors.

<u>Open Path Sensors</u>

As an alternative to stationary gas sensors staff researched open path sensors and found that they use a transmitter to transmit a beam to a reflector that sends the beam back. Detection of a targeted gas/emission such as VOCs is made when it makes contact with the beam. Staff did not find any oil and gas production sites using open path sensors but included this as an option. Since open path sensors operate continuously like stationary gas sensors, a potential emission reduction equivalent of 0.40 ton per day of VOC would be expected. See calculation performed in the previous section for additional details.

Engines Powered by Produced Gas

Staff is proposing requiring facilities that use their produced gas to power engines that drive oil producing wells to meet a NOx emission standard of 11 ppmv @ 15% O_2 on a dry basis. This emission limit was obtained from South Coast AQMD Rule 1110.2 Table 2 for stationary engines. Emission reductions from this proposal were calculated based on the assumption that an unregulated engine used in this service has equivalent emissions of a spark ignition engine.[6] The reason that staff assumed a spark ignition engine is that these engines were powered by produced gas versus diesel as with typical compression ignition engines. With the proposed exhaust emission controls using a 3-way catalyst with an air-to-fuel ratio control, staff expects a reduction in NOx emissions of approximately 90% based on current technology performance of a 3-way catalyst.

To determine potential reductions in NOx emissions through the installation of exhaust emission controls, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engine rated at 50 bhp
- Engine operates continuously: 24 hours, 365 days
- 90% reduction efficiency for catalyst system
- Calculation – (90% reduction) x (1.5 g/hp-hr) x (50 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.0018 ton NOx/day
- Using these assumptions, a potential reduction of 0.0018 ton per day of NOx is attributable to the installation of exhaust emission controls

It should be noted that this calculation is on a per engine basis and the total emissions reduced will vary by the actual number of engines retrofitted and used at oil and gas production sites.

Microturbines Powered by Produced Gas

As an alternative to routing produced gas to engines, staff acknowledges that stationary gas turbines can also use produced gas resulting in a similar NOx emission reduction of approximately 90%. Staff is proposing that the NOx emission limit for microturbines be 9 ppmv @ 15% O_2 on a dry basis, which was obtained from Table 1 from Rule 1134 for stationary gas turbines. Emission

[6] California Air Resources Board – PERP Regulation : https://ww2.arb.ca.gov/sites/default/files/2020-03/PERP_Reg_12.5.18R.pdf, page 21, accessed on 11/1/2023

reductions from this proposal were calculated based on the assumption that one microturbine would replace three unregulated engines with equivalent emissions of spark ignition engines, as referenced above in the "Engines Powered by Produced Gas" section. Staff selected this ratio as representative of the amount of gas needed to sustain operation of a small microturbine relative to the amount of gas needed to sustain operation of an engine.

To determine potential reductions in NOx emissions through the installation of a microturbine replacing engines operating on produced gas, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engines rated at 50 bhp (3 engines = 150 hp capacity)
- Engine operates continuously: 24 hours, 365 days
- Emission factor for a microturbine of 0.16 g/hp-hr (from manufacturer datasheet)
- Calculation – (1.5 g/hp-hr – 0.16 g/hp-hr) x (150 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.005 ton NOx/day
- Using these assumptions, a potential reduction of 0.005 ton per day of NOx is attributable to the installation of one microturbine in lieu of three engines

It should be noted that this calculation is on a per microturbine basis and the total emissions reduced will vary by the actual number of microturbines installed and used at oil and gas production sites.

Use of Tier 4 Final Workover Rigs

Staff is proposing that workover rigs be powered by engines that are at least rated as Tier 4 Final. By requiring the use of Tier 4 Final engines on workover rigs, staff expects a significant reduction in emissions whenever the use of workover rigs is required. Staff assumed that the emissions from current workover rigs to be at Tier 2 levels. Staff also assumed that a workover rig is required four times per year at each site, is used four days per week, and eight hours per day. Workover rig engine size will vary. Staff assumed a rating of 600 hp to be representative of a typical engine. As noted previously, staff identified that there are approximately three hundred and thirty sites. To service these sites, staff estimated that approximately 40 rigs may be needed to cover potential demand.

To determine potential reductions in NOx emissions through the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig, staff performed the following calculation:

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Tier 4 Final NOx emission factor of 0.30 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day

- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr – 0.30 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.51 ton NOx/day
- Using these assumptions, a potential reduction of 0.51 tons per day of NOx is attributable to the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig

Electrification of Workover Rigs

Staff researched the feasibility of requiring oil and gas production facilities to use electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule development process, staff visited multiple oil and gas production sites and spoke to industry representatives and vendors. From these discussions and interaction, staff was made aware that the use of an electrically powered drilling/workover rig was only available at two sites. Staff visited these sites and found that these two sites were unique in that each had dedicated infrastructure installed to meet the electrical demands of these electrified drilling/workover rigs. Staff noted that these electrified drilling/workover rigs were designed to only operate at their respective sites and were not mobile.

To determine potential reductions in NOx emissions through the use of an electrified rig, staff performed a calculation similar to one comparing using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig. In this case, however, an electrified rig is assumed to emit zero NOx emissions.

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day
- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lbs) x (1 yr/365 days) = 0.54 ton NOx/day
- Using these assumptions, a potential reduction of 0.54 ton per day of NOx is attributable to the requirement of using an electrified rig versus a rig equipped with Tier 2 engines

Elimination of Odorants

Due to concerns raised by stakeholders, staff proposes to eliminate the use of odorants. Although some odorants may contain VOC material, the overall reduction in VOC emissions associated with this activity is not expected to be significant.

Improved Signage

By producing and installing new signs at oil and gas production sites, some additional emission reductions may be generated, but these are expected to be one-time occurrences and are not expected to be significant.

COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control is measured in terms of the control cost in dollars per ton of air pollutant reduced. The costs for the control technology include purchasing, installation, operation, maintenance, and permitting. Emission reductions were calculated for each requirement and based on estimated baseline emissions. The 2022 AQMP established a cost-effectiveness threshold of $36,000 per ton of VOC reduced. A cost-effectiveness that is greater than the threshold of $36,000 per ton of VOC reduced requires additional analysis and a hearing before the Governing Board on costs. The 2022 AQMD also established a cost-effectiveness threshold of $325,000 per ton of NOx reduced. A cost-effectiveness that is greater than the threshold of $325,000 per ton of NOx reduced would also require additional analysis and a hearing before the Governing Board on costs.

The cost-effectiveness is estimated based on the present value of the retrofit cost, which was calculated according to the capital cost (initial one-time equipment and installation costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment multiplied by a present worth factor).

Cost-Effectiveness (CE) = Present Worth Value (PWV) / Emission Reduction (ER)

PWV = Total Install Cost (TIC) + Present Worth Factor (PWF) x Annual Cost (AC)

Capital costs are one-time costs that cover the components required to assemble a project. Annual costs are any recurring costs required to operate equipment. Costs were obtained for OGI monitoring, retrofitting an existing engine powered by produced gas to drive a well, microturbines powered by produced gas, Tier 4 Final equipped workover rigs, and electrification of workover rigs.

OGI Monitoring

Staff is proposing the monthly use of OGI equipment as a tool to find leaks from equipment regulated by this rule. Costs for this proposal were obtained from vendors and facilities. Some oil and gas companies already use an OGI camera and staff was able to obtain further cost information such as maintenance and labor. In addition, South Coast AQMD retains OGI cameras, and training and maintenance cost information was available.

The following information was used to calculate the cost-effectiveness of purchasing and using an OGI camera:

- Number of oil and gas companies to be at approximately 80
- Cost of an OGI camera = $120,000 with a 10-year life span
- Annual maintenance = $1000
- Training = $1,000 every two years ($500 per year)
- In-House labor 1 person working 8 hours/day at $50/hr = $400/day
- Monthly inspections = 12/year
- Emission reduction based on analysis conducted previously = 0.27 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $120,000 x 80 cameras = $9,600,000
- AC = $1000 [maintenance] + $500 [training] + (1 person x 8 hr/day x $50/hr x 12 inspections/yr) [labor] = $6300 per OGI camera or $504,000 for 80 cameras
- PWV = $9,600,000 + 8.111 x $540,000 = $13,688,000
- ER = (0.27 tpd VOC) x (365 day/yr) x (10 years) = 990 tons VOC
- CE = $13,688,000 / 990 tons VOC reduced = $13,800/ton VOC reduced

Based on these assumptions, the cost-effectiveness for requiring monthly inspections using OGI cameras is calculated to be $13,800/ton VOC reduced.

Fenceline Monitoring

Stationary Gas Sensors

As an alternative to OGI cameras, staff researched the use of stationary gas sensors for the monitoring of VOCs. Costs used in this analysis were obtained from oil and gas facilities that have already installed stationary gas sensors.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites is approximately 330
- Cost of each sensor = $3,115
- Number of sensors at a site = 14
- Installation cost of $30,000

- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.40 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = (14 sensors x $3,115 + $30,000), all multiplied by 330 sites = $24,291,300
- AC = $10,000 x 330 sites = $33,000,000
- PWV = $24,291,300 + 8.111 x $33,000,000 = $51,057,600
- ER = (0.40 tpd VOC) x (365 day/yr) x (10 years) = 1,460 tons VOC
- CE = $51,057,600 / 1,496 tons VOC reduced = $34,971/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of stationary gas sensors is calculated to be $34,971/ton VOC reduced.

Staff considered both stationary gas sensors and the use of OGI cameras and calculated the incremental cost-effectiveness for both options. This analysis is included in the section "Incremental Cost-Effectiveness".

<u>Open Path Sensors</u>

Open path sensors are an alternative to stationary gas sensors and work in a different way by having a beam projected from a transmitter to a reflector. Staff did not find an oil and gas site using this type of technology; however, staff is aware that it is being used at oil refineries. The staff report from South Coast AQMD Rule 1178 included cost-effective data which was used for this staff report.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites to be at approximately 330
- Cost of each sensor = $190,000
- Installation cost per sensor = $190,000
- Number of sensors at a site = 4
- Estimated life span of 20 years
- Annual maintenance = $5,000
- Emission reduction based on analysis conducted previously = 0.40 tpd VOC

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = (4 sensors x $380,000), all multiplied by 330 sites = $501,600,000
- AC = $5,000 x 330 sites = $1,650,000

- PWV = $501,600,000 + 13.59 x $1,650,000 = $503,250,000
- ER = (0.40 tpd VOC) x (365 day/yr) x (20 years) = 2,920 tons VOC
- CE = $503,250,000 / 2,920 tons VOC reduced = $172,346/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of open path sensors is calculated to be $172,346/ton VOC reduced.

It should be noted that this type of enhanced leak detection technology exceeds the cost-effective VOC threshold.

Engines Powered by Produced Gas

Staff is proposing that engines that are powered by produced gas and are used to drive an oil producing meet a NOx standard of 11 ppmv @ 15% O_2 on a dry basis. Staff researched technologies that could be used to meet this standard and also the option to replace these engines with microturbines which is discussed in the next section. Staff obtained cost information for the technology upgrades from vendors that supply and service engines to oil and gas facilities. Staff also used cost information for exhaust emission controls that was collected for the November 2019 amendment to Rule 1110.2.

The following information was used to calculate the cost-effectiveness of upgrading engines powered by produced gas used to drive an oil producing well:

- Cost of 3-way catalyst = $5,000
- Cost of air/fuel ratio controller = $1,000
- Cost of installation of parts = $5,000
- Estimated life span of 3 years for parts operating 24 hrs/day
- Annual maintenance = $1,000
- Emission reduction based on analysis conducted previously = 0.0018 tpd NOx

- PWF = 2.78 for a 3-year life expectancy at 4% interest rate
- TIC = $11,000
- AC = $1,000
- PWV = $11,000 + 2.78 x $1,000 = $13,775
- ER = (0.0018 tpd NOx) x (365 day/yr) x (3 years) = 1.971 tons NOx
- CE = $13,775 / 1.971 tons NOx reduced = $7,000/ton NOx reduced

Based on these assumptions, the cost-effectiveness for upgrading engines powered by produced gas used to drive an oil producing well is calculated to be $7,000/ton NOx reduced.

Microturbines Powered by Produced Gas

As an alternative to requiring emissions controls on engines, staff is proposing that microturbines replace engines that use produced gas. The NOx emission standard for microturbines is 9 ppmv @ 15% O_2 on a dry basis. It is assumed that one microturbine would replace three engines that are each being used to drive three wells. Staff obtained cost information on microturbines from a local vendor that offers them for sale with South Coast AQMD's jurisdiction.

The following information was used to calculate the cost-effectiveness of purchasing a microturbine rated at 65 kilowatts (kW):

- Cost of microturbine = $150,000
- Microturbine installation cost = $300,000
- Cost of electric motor = $5,000 (x 3 for 3 electric motors) needed to drive wells
- Installation of electric motors = $5,000 (x3 for 3 electric motors) needed to drive wells
- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.005 tpd NOx

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $480,000
- AC = $10,000
- PWV = $480,000 + 8.111 x $10,000 = $561,110
- ER = (0.005 tpd NOx) x (365 day/yr) x (10 years) = 18.25 tons NOx
- CE = $561,110 / 18.25 tons NOx reduced = $30,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for installing a microturbine powered by produced gas used to drive an oil producing well is calculated to be $30,700/ton NOx reduced.

Use of Tier 4 Final Workover Rigs

Staff is proposing that engines on workover rigs be at least rated as Tier 4 Final. Staff obtained cost data from several operators that have either upgraded or replaced their workover rigs to be equipped with Tier 4 Final engines.

The following information was used to calculate the cost-effectiveness of purchasing a Tier 4 Final engine equipped workover rig:

- Cost of Tier 4 Final engine equipped workover rig = $1,000,000
- Estimated life span of 20 years
- Estimated number of Tier 4 Final engine equipped workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40

- Annual maintenance = $20,000
- Emission reduction based on analysis conducted previously = 0.51 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $1,000,000 = $40,000,000
- AC = 40 rigs x $20,000 = $80,000
- PWV = $40,000,000 + 13.59 x $800,000 = $50,872,000
- ER = (0.51 tpd NOx) x (365 day/yr) x (20 years) = 3,723 tons NOx
- CE = $50,872,000 / 3,723 tons NOx reduced = $13,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with engines that are at least rated as Tier 4 Final is calculated to be $13,700/ton NOx reduced.

Electrification of Workover Rigs

Staff researched the feasibility of oil and gas production facilities using electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule making process staff received cost information from the only two operators that currently have an electrified workover rig on their respective sites. No other facility was found to have an existing electrified rig. Staff found that a substation would need to be installed at *each* site in order to meet the electrical demands that an electrified workover rig would require.

The following information was used to calculate the cost-effectiveness of requiring an electrified workover rig:

- Number of oil and gas sites to be at approximately 330
- Cost of electrified workover rig = $10,000,000
- Cost of substation per site = $5,000,000
- Estimated life span of 20 years
- Estimated number of electrified workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40
- Annual Maintenance for the rigs = $20,000
- Annual Maintenance for the substations = $10,000
- Emission reduction based on analysis conducted previously = 0.54 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $10,000,000 + 330 substations x $5,000,000 = $2,050,000,000
- AC = 40 rigs x $20,000 + 330 substations x $10,000 = $4,100,000
- PWV = $2,050,000,000 + 13.59 x $4,100,000 = $2,054,100,000
- ER = (0.54 tpd NOx) x (365 day/yr) x (20 years) = 3,942 tons NOx

- CE = $2,054,100,000/ 3,942 tons NOx reduced = $521,080/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with an electrified rig (and the installation of the requisite infrastructure) is calculated to be $521,080/ton NOx reduced.

It should be noted that the electrification of workover rigs exceeds the cost-effective NOx threshold.

Elimination of Odorants

The elimination of odorants is not expected to produce any significant reductions in VOC emissions. Moreover, the elimination of odorants does not result in any new cost incurred by operators, but rather it is a cost that is no longer spent. Therefore, no cost-effective analysis was conducted for this proposal.

Improved Signage

By producing and installing new signs at oil and gas production sites, some additional emission reductions may be generated, but these are expected to be one-time occurrences and are not expected to be significant. Staff acknowledges that there will be one-time costs associated with this proposal but does not consider these costs to be significant. Therefore, no cost-effective analysis was conducted for this proposal.

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors.

Options for Enhanced Monitoring

Staff conducted an incremental cost-effectiveness for OGI camera usage and stationary gas sensor monitoring as they both use enhanced technology for the detection of fugitive VOC emissions. Staff used the following formula to calculate incremental cost-effectiveness where option 1 is OGI monitoring and option 2 is stationary gas monitoring:

$$\text{Incremental Cost-Effectiveness} = \frac{\text{Cost of Option 2} - \text{Cost of Option 1}}{\text{Benefit of Option 2} - \text{Benefit of Option 1}}$$

$$\text{Incremental Cost-Effectiveness} = \frac{\$51{,}057{,}600 - \$13{,}688{,}000}{1{,}460 \text{ tons} - 990 \text{ tons}}$$

The incremental cost-effectiveness of using stationary gas sensors compared to OGI technology is calculated to be $79,510/ton VOC reduced.

Staff found that it was not cost-effective to use stationary gas sensors relative to OGI technology and therefore recommends the use of OGI technology as it is a more active and robust use of enhanced leak detection technology.

Options for Tier 4 Final Engine versus Electrification

Staff conducted an incremental cost-effectiveness for Tier 4 Final workover rigs versus electrified workover rigs where option 1 is the use of Tier 4 Final workover rigs and option 2 is the use of electrified workover rigs:

$$\text{Incremental Cost-Effectiveness} = \frac{\$2{,}050{,}000{,}000 - \$50{,}872{,}000}{3{,}942 \text{ tons} - 3{,}723 \text{ tons}}$$

The incremental cost-effectiveness of using electrified workover rigs compared to Tier 4 Final workover rigs is calculated to be $9,100,000/ton VOC reduced.

Staff found that it was not cost-effective to use electrified workover rigs relative to Tier 4 Final workover rigs.

SOCIOECONOMIC IMPACT ASSESSMENT

A socioeconomic impact assessment will be conducted and released for public review and comment at least 30 days prior to the South Coast AQMD Governing Board Hearing, which is scheduled for August 2, 2024 (subject to change).

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) Guidelines Sections 15002(k) and 15061, the proposed project (PAR 1148.1) is exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). A Notice of Exemption will be prepared pursuant to CEQA Guidelines Section 15062, and if the proposed project is approved, the Notice of Exemption will be filed with the county clerks of Los Angeles, Orange, Riverside, and San Bernardino counties, and with the State Clearinghouse of the Governor’s Office of Planning and Research.

DRAFT FINDINGS UNDER HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

Health and Safety Code Section 40727 requires that the Board make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. In order to determine compliance with sections 40727 and 40727.2, a written analysis is required comparing the proposed rule with existing regulations.

Necessity

A need exists to amend PAR 1148.1 to implement best available retrofit control technology and emission reduction strategies recommended in the WCWLB and SLA CERPs as part of the AB 617 commitment.

Authority

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

Clarity

PAR 1148.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by them.

Consistency

PAR 1148.1is in harmony with and not in conflict with or contradictory to existing statutes, court decisions, or state or federal regulations.

Non-Duplication

PAR 1148.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In amending this rule, the following statutes which the South Coast AQMD hereby implements, interprets, or makes specific are referenced: Health and Safety Code Sections 39002, 40001, 40406, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to oil and gas production activities. Because PAR 1148.1 does impose new inspection and reporting requirements, a comparative analysis was conducted.

Table 4-1: Comparative Analysis

Topic	South Coast AQMD Rule 1148.1 Oil and Gas Notification Rule	San Joaquin Valley Air Pollution Control District	CalGEM	State of Colorado, Air Quality Control Commission	U.S. EPA
Newly Added Inspection Requirements	• Inspections with OGI camera • Use of Tier 4 Final diesel engines on workover rigs • Establish NOx limits for combustion equipment	• OGI usage requires quantification within 2 days of leak detection • No relevant requirements for Tier 4 Final engines or NOx limits observed	• OGI usage allowed for inspections • No relevant requirements for Tier 4 Final engines or NOx limits observed	• OGI allowed as alternative instrument monitoring and on drones • Tier 4 engines required in impacted communities • No relevant NOx limits observed	• OGI usage allowed with specific requirements for operator and equipment • No relevant requirements for Tier 4 Final engines or NOx limits observed
Other amendments	• Notification when leak >25,000 ppmv detected • Banning use of odorants	• Notification required to request extension for repair of leaking component • No relevant requirements on odorant use observed	• Notification required for leaks > 50,000 ppmv or for leaks >10,000 ppmv persisting more than 5 days • No relevant requirements on odorant use observed	• Notification within 5 days of discovery for unrepaired leaks • No relevant requirements on odorant use observed	• No relevant requirements for notification or odorant use observed
Notes		Reviewed Rule 4401 – Steam-Enhanced Crude Oil Production Wells	Reviewed Subarticle 13. Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities	Reviewed Regulation Number 7 of Colorado state Air Quality Control Commission regulations	Reviewed Appendix K "Determination of VOC and Greenhouse Gas Leaks Using Optical Gas Imaging" document
Links	https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1148-1	https://ww2.valleyair.org/media/be1niqvx/rule-4401.pdf	https://ww2.arb.ca.gov/sites/default/files/2024-05/2024OilandGasRegulationunofficial.pdf	https://cdphe.colorado.gov/aqcc-regulations	https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf

APPENDIX A – RESPONSES TO COMMENT LETTERS

Responses to Comments - Table of Contents

Comments from Public Workshop

Comment PW-1: Shannon Smith, Regulatory Compliance Supervisor from Signal Hill Petroleum had two questions: for OGI inspections, did staff factor in the cost of a toxic vapor analyzer (TVA) as part of the OGI camera cost-effectiveness? Second, did staff do mockup of the proposed signage requirement with four-inch lettering?

Response: Staff did not account for the cost of a TVA since using one during the proposed monthly OGI inspections is optional. Should an owner or operator opt to have a potential repair period consistent with South Coast AQMD Rule 1173, then the use of a TVA would be at their discretion. Second, staff initially proposed to include the signage requirements as promulgated in South Coast AQMD 1460 subdivision (g). However, since the Public Workshop was held, staff met with Signal Hill Petroleum staff and observed that the sign with four-inch lettering is excessively large. Staff is, therefore, proposing that lettering to be two-inches instead of four-inches which is still readable from a public street.

Comment PW-2: Emma Silber, Climate Justice Associate from Physicians for Social Responsibility expressed several concerns. First, by allowing the continued use of neutralizing agents, toxic contaminants would still be released into the air. Second, she was opposed to allowing Tier 4 Final engines to be used rather than requiring electrification. She stated that she had heard of a site that plugged in their workover rig into the electrical grid. Lastly, she expressed a concern over the efficiency of NOx incinerators.

Response: Staff is addressing the concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed. If a neutralizing agent were used by a site, these prohibitions are intended to prevent the use of air toxics and to keep the chemical from becoming airborne. Second, staff researched the potential electrification of workover rigs. Staff found that although options may exist to use electrically-powered drilling rigs, no commercially available option existed for workover rigs. Lastly, staff noted that NOx incinerators may be used for site-specific, soil remediation projects which would be regulated by South Coast AQMD Rule 1166.

Comment PW-3: Justin Martin, Manager from Pacific Coast Energy Co, asked if detection of visible vapors is in regards with the naked eye or with OGI equipment.

Response: Visible vapors is a new definition for this rule and is defined as VOC vapors detected visually by an operator or with an OGI device.

Comment PW-4: Richard Parks, President from Redeemer Community Partnership, made several comments. First, he commented that Warren E&P had electrified their workover operations and asked why we did not include this equipment in staff's technology assessment and analysis. Second, Mr. Parks expressed concern that allowing the use of neutralizing agents may not solve the issue of toxic air contaminants causing birth defects and that an odorant called "Chemco Odor Control Jasmine" had an endocrine disruptor. Lastly, Mr. Parks then requested information with whom the South Coast AQMD had spoken with regarding the reinjection of methane because reinjection was what he considered a zero-emission solution to produced gas.

Response: Staff had conducted a site visit to Warren E&P in Wilmington, prior to the Public Workshop, and found that an electrically-powered workover/drilling rig that was on site had been removed several years ago. While on-site, staff witnessed a diesel-powered workover rig conducting general well maintenance. Based on staff's direct observations, it was noted that Warren E&P does not operate an electrified workover nor electrified drilling rig. Second, staff is addressing concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed. If a neutralizing agent were used by a site, these prohibitions are intended to prevent the use of air toxics and to keep the chemical from becoming airborne. Also, staff reviewed the Safety Data Sheet for "Chemco Odor Control Jasmine" and found that it does contain a prohibited chemical that is listed in Rule 1401. Therefore, under the proposed prohibition, it would no longer be allowed to be used. Lastly, staff has met with staff from the city of Los Angeles Planning Department and found that the City of Los Angeles discourages the practice of gas reinjection within urban areas due to concerns of back pressure buildup underneath residents' homes and also due to the major gas leak that took place at Aliso Canyon a few years ago. In addition, since the Public Workshop took place staff met with CalGEM personnel and found that CalGEM has jurisdiction over the reinjection and storage of gas underground.

<u>Comment PW-5:</u> Mark Abramowitz, President from Community Environmental Services, asked why South Coast AQMD has not done a BARCT analysis for fuel cell technology and if South Coast AQMD had looked at the quality of the produced gas that is generated at oil and gas sites.

Response: Staff contacted several vendors of fuel cell technology and determined based on the information provided that the technology is not readily available for use on workover rigs. Staff acknowledges that this technology could become a viable option in the future. Second, operators that sell the produced gas to local gas companies must clean it up prior to selling it. Operators need to remove, at minimum, excess water prior to being used in microturbines.

<u>Comment PW-6:</u> Tianna (last name not provided), Environmental Justice Program Manager, raised two concerns. First, she questioned why electrified workover rigs were not required to be used. Second, she expressed concern with odorants and neutralizing agents. Tania asked if costs have been used in a cumulative way to include costs to taxpayers and residents due to particulate

emissions for diesel-fueled workover rigs and concerns over endocrine disruptors in neutralizing agents. Concerns over cumulative harm were also raised.

Response: Staff conducted a cost-effectiveness analysis of proposed options and used the guidance for VOC and NOx cost-effectiveness found in the 2022 South Coast Air Quality Management Plan. In determining what is considered cost-effective for NOx, health effects were included. Staff conducted a cost-effective and emission reduction analyses for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines, it was not cost-effective to use electrically-powered engines. Lastly, staff is addressing concern over the use of neutralizing agents by proposing that no toxic air contaminants listed in South Coast AQMD Rule 1401 would be allowed in any neutralizing agent and that no atomization of any neutralizing agents would be allowed.

Comment PW-7: Mark Abramowitz expressed concern over the allowance of 0.1% by weight of banned toxic air contaminants and that that amount would not be allowed in drinking water.

Response: Drinking water has much stricter standards because it is directly ingested. The allowance of 0.1% by weight is included for trace contaminants that are not purposely included in the odor neutralizer.

Comment PW-8: Erica Blyther, Petroleum Administrator for the City of Los Angeles Office of Petroleum and Natural Gas Administration and Safety, stated that she was pleased with South Coast AQMD requiring monthly OGI inspections and inquired on what constitutes a certified inspector for OGI device use.

Response: Thank you for your comment. There are now several vendors of OGI cameras and the intent of requiring the user of an OGI camera to complete a manufacturer's certification or training program is to ensure that the user of such equipment is well versed in the use of such equipment. Staff also recognizes that the training course(s) may differ depending on the manufacturer.

Comment PW-9: Emma Silber asked if detected leaks during inspections would be made public.

Response: Since the Public Workshop was held, staff is proposing to require the operator to submit a notification whenever a leak is quantified and found to be greater than 25,000 ppmv of VOC. For those that have signed up to receive Rule 1148.2 notifications, they will now also receive notifications for reported leaks greater than 25,000 ppmv of VOC.

Comment Letter 1: Signal Hill Petroleum, Received 2/9/2024

SIGNAL HILL PETROLEUM

American Energy.
American Jobs.

February 7, 2024

Jose Enriquez, Air Quality Specialist
South Coast Air Quality Management District
Planning, Rule Development and Area Sources
21865 Copley Dr.
Diamond Bar, CA 91765

RE: Signal Hill Petroleum, Inc.'s comments regarding preliminary draft language of Proposed Amended Rule 1148.1.

Dear Mr. Enriquez and 1148.1 Rulemaking Team,

Signal Hill Petroleum (SHP) is a privately-owned California -based energy company that specializes in the exploration and production of crude oil and natural gas in urban areas. With a set of core values rooted in a transparent business philosophy, honest approach, and concern for the environment, our company strives to be an excellent neighbor and community partner. The SHP Regulatory Team has been following the development of Proposed Rule 1148.1. Per your request, we have drafted comments on the recently released draft rule language. Please see our comments below:

> (c)(34) WORKOVER RIG is a mobile piece of equipment used to perform one or more operations on an oil producing well or water injection well

This definition, while also present in Rule 1148.2, is too broad. A "mobile piece of equipment" could include trucks and other smaller tools. We suggest that you use ARB's definition of workover rig (2449(c)(62)): "a mobile self-propelled rig used to perform one or more remedial operations, such as deepening, plugging back, pulling and resetting liners, on a producing oil or gas well to try to restore or increase the well's production." 1-1

> (d)(17) Effective [Three years from date of rule amendment], the operator of an oil and gas production facility shall use workover rigs that are equipped with an engine that meets the emissions standards of a Tier 4 Final engine. 1-2

2633 Cherry Ave. Signal Hill, CA 90755 | T: 562. 595.6440 | F: 562. 426.4587 | W: shpi.net

While SHP already has all Tier 4 Final Workover Rigs in our fleet, we would like to point out that this is already being regulated by the California Air Resources Board In-Use Off-Road Diesel-Fueled Fleets Regulation, in which every fleet in California phases out older engines for new Tier 4 Final or electric engines. 1-2 Cont.

> (d)(13) …signage shall: (A) Be installed within 50 feet of the main entrance to the facility and in a location that is visible to the public; (B) Measure at least 30 inches wide by 30 inches tall; (C) Display lettering at least 4 inches tall with text color contrasting with the sign background; (D) Located at least 4 feet above grade from the bottom of the sign;

As currently proposed these signs would be nearly impossible to achieve, impractical to maintain, and an eye sore to the community. SHP has made a quick example of what is being proposed and the pictures are an attachment to this letter. The first requirement, (d)(13)(A) which requires the sign to be installed within 50 feet of the entrance, is too specific and impractical. An operator could post the signs across the street or inside their facility and still be fully compliant with the rule. The second requirement (d)(13)(B), which requires the sign to be at least 30" by 30", should be reconsidered. The 4" lettering does not fit on a 30" by 30" poster. This is also not a typical poster size. 24" by 36" would be more standard although still much larger than any other sign SHP currently has. 1-3 Our company signs with our Facility name and phone number measure 30" by 12" and our neighbors have no problem reading them. The third requirement (c)(13)(C), which requires 4" lettering, is not practical. As you can see from the attached photos, 4" lettering in both English and Spanish would be a billboard rather than an entrance sign. We also created an example of 2" lettering in English only and it is also huge and not practical to post at our facilities. The fourth requirement (d)(13)(D) requires the sign to be 4 feet off the ground minimum. If the signs are posted on the entrance fence (and not 50 feet away) then the sign can be no higher than 2 feet since most standard fences are 6 feet tall. Anything protruding above that could interfere with barbed wires and the security of the enclosure.

This one-size-fits-all approach does not work for urban upstream oil and gas operations. It may make sense for a large facility distanced from the public view, such as in Rule 1460, but doesn't make sense for production sites next door to businesses and homes. We recommend editing the original language to allow for flexibility among operators while still achieving your goal of having the signs visible and readable by the public. We specifically recommend removing requirements (d)(13)(A) through (d)(13)(D) and either not specifying a size or recommending a standard size for the signage without text size requirements.

> (e)(6)(B)(ii) When visible vapors are detected using an OGI Device, use an appropriate analyzer in compliance with paragraph (j)(1) to quantify the visible vapors in ppmv concentration within 48 hours of when the vapors are detected; 1-4

SHP owns three OGI cameras and currently uses them to detect any potential leaks in our facilities. While monthly OGI inspections and recordkeeping will be challenging, we believe it is feasible to accomplish this. What makes the OGI camera so useful is that our operators can visit a facility, FLIR the facility, and if they find a leak, they can repair it immediately and move on. If our crew needed to quantify the leak before repairing it, that would require time to (1) acquire a TVA, (2) find and measure the leak with the TVA, (3) report the leak to the district and (4) look up the repair thresholds in accordance with Rule 1173, all before fixing the actual leak. This is time spent allowing the leaks to continue in order to quantify and document the leaks. Also, SHP has looked into and rented a TVA (Total Vapor Analyzer) in compliance with EPA specifications and found that the maintenance and calibration requirements were extremely onerous. Calibration gases would have to be stored on-site and the TVAs calibrated every day. In addition, the TVAs require maintenance more often than a FLIR camera. SHP would have to purchase multiple TVA units to always have two or three units on hand in case of a leak in order to comply with this requirement.

1-4
Cont.

SHP recommends that you adopt the rule language in Rule 1178 (f)(4)(A) "If determined that Visible Vapors are emitted from components required to be maintained in a Vapor Tight Condition or in a condition with no Visible Gaps, the owner or operator shall make necessary repairs or adjustments… within 3 days". This would ensure that leaks are fixed promptly and that all components could be inspected in a timely manner, once a month in compliance with the new proposed rule requirements.

Please let us know if you have any questions or wish to discuss our comments further. You may contact Shannon Smith at (562) 326-5246 or ssmith@shpi.net.

Sincerely,

Shannon Smith
Regulatory Compliance Supervisor

Attachments:
Photo #1 – Proposed signage with 4" lettering in English only
Photo #2 – Proposed signage with 2" lettering in English only

Comment 1-1: The definition for workover rig was incorporated from South Coast AQMD Rule 1148.2 for consistency among rules that use this definition. The definition is somewhat vague so that it may allow for future technologies that could become commercially available such as electrically-powered or fuel-cell powered rigs. In addition, adding that it be self-propelled would not cover all rigs since some exist that use a secondary engine to do well work and the primary engine to drive the rig itself.

Comment 1-2: Staff conducted a cost-effective and emission reduction analyses for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines, it was not cost-effective to require the use of electrically-powered engines. In addition, staff researched a company that already manufactures electric drilling rigs and found that the footprint and power requirements such a rig would require to be too large for the majority of oil and gas sites that are found within South Coast AQMD's jurisdiction as many of these sites are less than a half-acre in size. Additionally, a substation would be necessary as well as power lines and electric grid that could handle the power requirements of 373 kilowatts which is equivalent to a 500-HP diesel engine. Finally, drilling activities represent a small fraction of activities at oil and gas facilities.

CARB already has a requirement for In-Use Off-Road Diesel-Fueled Fleets regulation, however, depending on the size of the operator's fleet, it could take longer than the effective date of this rule before an operator would be required to upgrade their fleet by CARB's compliance date. Therefore, this requirement aims to bridge the gap that may exist between this rule and CARB's rule.

Comment 1-3: Staff reviewed the signage requirements and agreed that the minimum size of the lettering was too large and has since reduced the minimum size from 4 inches to 2 inches. This change will not affect the intent of this updated requirement which aims to have signage be visible from a public street.

Comment 1-4: Staff agrees that it is preferable to repair leaks discovered with an OGI camera sooner rather than later and the proposed rule language has been updated such that any leaks found exclusively with an OGI camera shall be repaired within twenty-four hours of discovery. If using an OGI camera in conjunction with a calibrated handheld device that can quantify leaks, the operator can follow Rule 1173 Repair Period Table which could give the operator additional time to repair those leak(s).

Comment Letter 2: STAND LA, Received 2/15/2024

February 10, 2024

Mr. Wayne Nastri, Executive Officer
South Coast Air Quality Management District
21865 Copley Dr, Diamond Bar, CA 91765

Re: Proposed Amended Rule 1148.1 - Oil and Gas

Dear Mr. Nastri:

Rule 1148.1 - Oil and Gas presents opportunities to substantially reduce nitrogen oxides (NOx) emissions and protect the health of residents, especially those of frontline communities. Southern California still needs to reduce smog-forming NOx by more than 100 tons per day in order to achieve the 1997 standard for ozone.[1]

The Stand Together Against Neighborhood Drilling (STAND-LA) coalition of frontline environmental justice organizations have actively participated in the Air District's AB617 and the 1148.1 rule-making processes to protect communities disproportionately impacted by air pollution.

We remain concerned that the proposed amended Rule 1148.1 does not yet incorporate our recommendations to reduce NOx and protect public health. We seek action in three areas:

1. Zero-emission workover operations
2. Zero toxics in odor counteractants (including neutralizing agents)
3. Zero combustion of produced methane

Zero-emission Workover Operations

We request that the Air District evaluate the cost effectiveness of using electric utility power or other zero-emission auxiliary sources to power the current fleet of mobile, diesel workover rigs. The adaptive electrification of existing mobile equipment may prove far more health and climate 2-1

[1] Los Angeles smog woes worsen as U.S. EPA threatens to reject local pollution plan, Los Angeles Times, (February 4, 2024)

protective than utilizing Tier-4 engines alone, and clearly more cost effective than acquiring $10 million electric rigs at each of 40 oil drill sites.

In 1999, the Breitburn oil company boasted that the use of an electrically-powered derrick at the Pico/Doheny Drill Site would eliminate most diesel emissions.[2] Diesel engine emissions are responsible for about 70% of California's estimated known cancer risk attributable to toxic air contaminants.[3] It is vitally important that the Air District evaluate lower-cost electrification alternatives to protect public health, rather than simply ruling out the most expensive approach.

2-1 Cont.

Zero toxics in odor counteractants

AB617 communities raised concerns about odorants because they contain powerful, toxic chemicals that cause birth defects, damage fertility, and cause multi-generational reproductive harm. Banning odorants while defining a new class of "neutralizing agents" that are permitted to have toxic air contaminants in their formulation up to 0.1%-by weight, does not address our community's concerns. It appears to be a change in words, but not practice.

The National Institute of Environmental Health Sciences notes,

> "Even low doses of endocrine-disrupting chemicals may be unsafe. The body's normal endocrine functioning involves very small changes in hormone levels, yet we know even these small changes can cause significant developmental and biological effects. This observation leads scientists to think that endocrine-disrupting chemical exposures, even at low amounts, can alter the body's sensitive systems and lead to health problems."[4]

The appropriate threshold for any toxics in odor counteractants is zero. We do not want more toxics dispersed in our communities. 2-2

Chemco Odor Control Jasmine is a common odor counteractant used at oil drill sites. It contains 4-no-nyl-pheenol, branched, ethoxylated, a endocrine disrupting chemical (EDC) that causes birth defects. Will the Air District categorize it as an odorant or a "neutralizing agent"? The public needs clarity from the Air District about which odor counteractants will be banned, which will be allowed, and which toxics that the Air District will allow in odor counteractant formulations, if any.

Our position remains that Chemco Odor Control Jasmine and other odor counteractants should not be permitted for use.

The staff report states that "Neutralizing agents work to 'knock out' or eliminate the odors." (page 3-5). That implies some sort of chemical manipulation, for example chemical decomposition. However, the manipulation that happens is often to human olfactory receptors--

[2] Neighbors Take On Pico Oil Drilling Site, Jewish Journal (November 25, 1999)

[3] Propper et al. 2015. Environmental Science & Technology **49**(19):11329–11339.

[4] National Institute of Environmental Health Sciences website. Downloaded 2/6/2024 from https://www.niehs.nih.gov/health/topics/agents/endocrine#:~:text=Even%20low%20doses%20of%20endocrine,significant%20developmental%20and%20biological%20effects.

knocking them out.[5] The presence of toxic gasses such as hydrogen sulfide or benzene are not eliminated, only the ability to detect them. Odor counteractants and "neutralizing agents" solve the wrong problem precisely. 2-2 Cont.

Toxic trespass into the bodies of our children and families must stop. The appropriate threshold for any toxics--including endocrine disruptors--in odor counteractants, odorants, and neutralizing agents is zero.

Zero combustion of produced methane
Reinjection of produced methane is a common zero emission oil field practice. The EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review affirms reinjection of produced gas into the oil field as an effective strategy for regulating greenhouse gasses (GHGs) and volatile organic compounds (VOCs) emissions for the Crude Oil and Natural gas source category pursuant to the Clean Air Act. We ask the District to evaluate reinjection of produced methane as a viable and cost effective zero emission practice that will enhance air quality and public health, especially for residents living near oil field operations. 2-3

STAND-LA would welcome the opportunity to discuss these concerns with the 1148.1 rule-making team. Thank you for your consideration.

Sincerely,
Richard Parks, President, Redeemer Community Partnership

Maro Kakoussian, Director of Climate and Health Programs, Physicians for Social Responsibility Los Angeles & STAND-LA Coalition Coordinator

Tianna Shaw Wakeman, Environmental Justice Program Manager, Black Women for Wellness

Reverend Louis Chase, Holman United Methodist Church

Rabeya Sen, Policy Director, Esperanza Community Housing

cc:
Mayor Pro Tem Larry McCallon, Chair
Supervisor Holly J. Mitchell, Vice Chair
Councilmember Michael A. Cacciotti

[5] Yosuke Fukutani, Masashi Abe, Haruka Saito, Ryo Eguchi, Toshiaki Tazawa, Claire A. de March, Masafumi Yohda, Hiroaki Matsunami, Antagonistic interactions between odorants alter human odor perception, Current Biology, Volume 33, Issue 11, 2023, Pages 2235-2245.e4, https://doi.org/10.1016/j.cub.2023.04.072. Accessed 2/8/2024 from https://www.sciencedirect.com/science/article/pii/S0960982223005547/

Senator (Ret.) Vanessa Delgado
Board Member Veronica Padilla-Campos
Mayor José Luis Solache
Trish Johnson, CARB Office of Community Air Protection
Liliana Nunez, CARB Air Pollution Specialist
Michael Krause, SCAQMD Assistant Deputy Executive Officer
Michael Morris, SCAQMD Planning and Rules Manager
Rodolfo Chacon, SCAQMD Program Supervisor
Jose Enriquez, SCAQMD Air Quality Specialist

Comment 2-1: Staff conducted cost-effective and emission reduction analysis for both Tier-4 Final engine upgrades and for electrification and found that while it was cost-effective to upgrade to Tier-4 Final engines it was not cost-effective to upgrade to electrification options. The cost to upgrade to Tier 4 Final engines was found to be $13,700/ton of NOx reduced whereas the cost to electrify was found to be $521,080/ton of NOx reduced.

In addition, staff researched a company that already manufactures electric drilling rigs and found that their footprint and power requirements would be too large for the majority of oil and gas sites that are found within South Coast AQMD's jurisdiction as many of these sites are less than a half-acre in size. Also, a substation would be necessary, as well as power lines and electric grid that could handle the power requirements of 373 kilowatts which is equivalent to a 500-HP diesel engine.

Staff acknowledges that future developments in electrification and other technologies such as fuel cells may mature enough to be usable in a variety of oil and gas sites including smaller urban and remote sites. This rule may be reopened in the future to add the use of cleaner technologies. In addition, CARB's Advanced Clean Fleet Regulation, as of 2024, will require electrification of workover rigs starting in year 2036 which would cover the entire state.

Comment 2-2: Staff has proposed the ban of the use of odorants. Additionally, staff has also restricted the use of neutralizing agents by prohibiting the use of any neutralizing agents that contain more than 0.1% by weight of toxic air contaminants pursuant to South Coast AQMD Rule 1401 – New Source Review of Toxic Air Contaminants. The Safety Data Sheet for the chemical that was referenced, "Chemco Odor Control Jasmine" includes a chemical listed in South Coast AQMD's Rule 1401 and would therefore no longer be allowed to be used once the effective date of this amended rule passes. To further reduce the chance of fugitive odors, staff is also prohibiting the atomizing of neutralizing agents whenever they are used.

Comment 2-3: Staff reviewed how produced gas is handled and recognizes that there are four options to use it: selling to a gas company, using it in onsite equipment such as microturbines or engines, reinjecting back into the ground, or flaring it.

Staff researched the reinjection of the produced gas into the ground and found that the City of Los Angeles discourages the practice of reinjection within urban areas due to concerns of back pressure build up underneath residents' homes and with the major gas leak that took place at Aliso Canyon a few years ago. In addition, CalGEM has jurisdiction over the reinjection and storage of gas underground and carries its own permit requirements.

The use of produced gas in microturbines is more favorable to the City of Los Angeles. Another advantage of using produced gas in microturbines is that it would provide some relief to the area's power grid and is a cleaner way to use it compared to flaring. Staff has added NOx requirements to ensure these emissions remain low. Staff has also added NOx emissions if the facility uses the produced gas in engines that drive oil and gas wells.

Comment Letter 3: Center for Biological Diversity, Received 2/15/2024

CENTER *for* BIOLOGICAL DIVERSITY *Because life is good.*

February 15, 2024

Jose Enriquez
Planning, Rule Development, and Implementation
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765

Re: Comments on Proposed Amended Rule 1148.1 – Oil and Gas

Dear Mr. Enriquez:

These comments are submitted on behalf of the Center for Biological Diversity regarding the Proposed Amended Rule 1148.1. Though the proposed amendments take positive steps in curbing harmful emissions from oil and gas production facilities, we remain concerned that the proposed amendments do not go far enough, namely in three areas:

1. Establishing zero-emission workover rig operations
2. Eliminating concerns regarding the use of odorants
3. Alerting the public in the event of leak detection

The Stand Together Against Neighborhood Drilling (STAND-LA) coalition is submitting comments with many of the same concerns. We agree with STAND-LA's comments and see our comments as supporting those while contributing added perspective.

1. Establishing Zero-Emission Workover Rig Operations

There is no disputing that electrifying workover rigs would drastically reduce harmful emissions from oil and gas well workover operations, but SCAQMD staff ultimately did not recommend electric rigs because of concerns about cost-effectiveness. It is indeed the case that electrified workover rigs exceed the cost-effectiveness threshold based on SCAQMD staff's analysis. However, it is noted that a "cost-effectiveness that is greater than the threshold of $325,000 per ton of NOx reduced would also require additional analysis and a hearing before the Governing Board on costs."[1] Similar guidance is given for exceeding the cost-effectiveness threshold for VOC reductions. Thus, the initial assessment Staff provided of cost-effectiveness does not preclude further consideration of electrifying workover rigs. Given that maximizing public health benefit should not be relegated to a mere cost equation, it seems appropriate to conduct additional analysis (perhaps including a search for lower-cost electrification alternatives) along with a hearing by the Governing Board to further weigh the merits of electrifying workover operations. 3-1

[1] Staff Report, p. 4-6.

Arizona . California . Colorado . Florida . N. Carolina . Nevada . New Mexico . New York . Oregon . Washington, D.C. . La Paz, Mexico
BiologicalDiversity.org

2. Eliminating Concerns Regarding the Use of Odorants

SCAQMD staff propose eliminating the use of odorants which have been traditionally used to mask odors coming from oil and gas production sites. This is the right action since odorants themselves can be a nuisance to communities and present health harms. However, as a substitute, staff propose what essentially constitutes another category of odorant—neutralizing agent. Purportedly, neutralizing agents "work to 'knock out' or eliminate the odors, as opposed to masking the odors," while containing none of the toxics "listed in Rule 1401 in quantities greater than 0.1 percent by weight."[2] This new category of odorant gives several reasons for concern.

First, the Rule 1401 list is not exhaustive, and could not possibly capture the full list of potential toxics that could be found in neutralizing agents. This is more so the case given that the neutralizing agents to be used are not identified. If neutralizing agents are to be taken as an innocuous alternative to odorants, the neutralizing agents allowed should be limited and clearly identified so that it is certain that none have the potential of yielding toxic emissions.

Second, the proposal limits Rule 1401 toxics to quantities less than 0.1 percent by weight, but this ignores the fact that some toxics have no true safe limit, including some on the Rule 1401 list.[3] For instance, bis(2-ethylhexyl)phthalate is on the Rule 1401 list, but it is part of the chemical group *phthalates*, which are well known endocrine disruptors.[4] Even low doses of endocrine-disrupting chemicals may be unsafe. Phthalates are very common, found in various fragrances, packaging, and cosmetics. Given their ubiquity, it is possible that such a chemical could end up in an unspecified neutralizing agent. Therefore, the provision on limiting neutralizing agents based on the Rule 1401 list is not rigorous enough to ensure non-harmful emissions. 3-2

Third, we are skeptical that a neutralizing agent would truly "knock out" or eliminate odors. To truly eliminate an odor would mean either eliminating the source of the odor or capturing vapors before they reach individuals. If this is truly the function of the proposed neutralizing agents, then great, but otherwise neutralizing agents constitute nothing more than a masking agent, same as classic odorants. And masking agents, rather than lessening the public nuisance posed by noxious fumes, merely cover up the presence of those fumes, thereby hiding the threat posed. Concerns regarding this could at least be partially addressed by providing a list of neutralizing agents to be used and the mechanisms by which they eliminate odors.

3. Alerting the Public in the Event of Leak Detection

SCAQMD staff have proposed the use of optical gas imaging (OGI) cameras to identify leaks at oil and gas production sites. This comes with two requirements: (1) "If a visible vapor is observed while inspecting with an OGI camera, the operator will be required to quantify in parts per million by volume (ppmv), any VOC emissions within 48 hours of when visible vapors are 3-3

[2] Staff Report, p. 3-6.
[3] SCAQMD, Regulation XIV – Toxics and Other Non-Criteria Pollutants, Rule 1041 – New Source Review of Toxic Air Contaminants (Accessed February 14, 2024), http://www.aqmd.gov/docs/default-source/rule-book/reg-xiv/rule-1401.pdf.
[4] National Institute of Environmental Health Sciences, Endocrine Disruptors (Accessed February 14, 2024), https://www.niehs.nih.gov/health/topics/agents/endocrine.

detected"; and (2) "should a visible vapor be quantified where the emission level triggers a repair, replacement, or removal of a component…then a notification to South Coast AQMD will also be required to be made within 24 hours of such quantification."[5] These requirements should come with additional notifications to the public.

3-3 Cont.

In the event of a leak, the public should be made aware of the leak quantity and composition and be provided with an assessment of whether there is a community threat posed. Further, should a repair be necessary, the public should be made aware of when the issue will be resolved, whether emissions will be ongoing during the repair, and whether there will be any nuisances resulting from the repair, such as noise or further emissions. Similar to the disclosures required under Rule 1148.2 of chemical usage and operations at oil and gas sites, Rule 1148.1 should require disclosures on leaks and measures to repair them.

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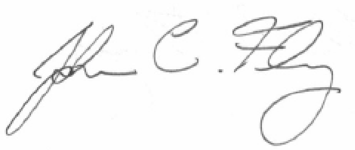
We appreciate your engagement thus far on the proposed Rule 1148.1 amendments. We implore you to consider these remaining concerns to make Rule 1148.1 the most robust and the most protective of community health.

Respectfully submitted,



John Fleming, Ph.D.
Senior Scientist
Center for Biological Diversity

[5] Staff Report, p. 3-6.

Comment 3-1: Please see response under comment 2-1.

Comment 3-2: Please see response under comment 2-2.

Comment 3-3: Staff has added an amendment to this rule to require the operator to submit a notification whenever a leak is quantified and found to be greater than 25,000 ppmv VOC. Notifications of reported leaks will be included in Rule 1148.2 notifications, for those who have signed up to receive them.

Comment Letter 4: FracTracker Alliance, Received 4/11/2024

FRACTRACKER ALLIANCE

Oil and Gas Fugitive Emissions from Combustors in the South Coast Air District

Requirements for California Air Resources Board (CARB)-approved emissions reduction technology and infrastructure cannot be a replacement for stringent monitoring and inspections. The existing work of grassroots organizations, including Redeemer Community Partnership, STAND-LA, PSR-LA and research groups like FracTracker Alliance, has monitored the compliance of drill sites in the Los Angeles Basin, and has shown the failures of engineering protections when sites are not regularly and thoroughly inspected.[1] This work includes the filmed documentation of many California Air Resources Board-approved burners observed to be operating poorly, inefficiently combusting methane and other volatile organic compounds (VOCs) that were still observable at concentrated levels in the exhaust streams. This is not an issue limited to southern California, as other geographies such as Colorado are also addressing the issue, as required by recent rulings of the U.S. Environmental Protection Agency.[2] 4-1

The implementation of the California Air Resources Board (CARB) Oil and Gas Methane Regulation in 2018 was the first time that regulators even considered that oil and gas operators should not be directly venting toxic and carcinogenic VOCs from wash and crude tanks. The elimination of venting was the most important regulatory intervention for reducing community exposures to hydrocarbon emissions. Operators were no longer able to completely disregard the uncontrolled release of pollutants and subsequent degradation of local airsheds, due to the establishment of actionable limits to methane concentrations in fugitive emissions. While the rule applies to all fugitive emissions and leaks, tank venting was by far the most widespread source of fugitive emissions, present at nearly every wellsite without existing evaporative emissions control systems (EVAP). 4-2

The various California air districts have taken a range of different approaches to the implementation of the CARB methane regulation. While the Yolo-Solano Air Quality Management District, with natural gas fields in the northern San Joaquin Valley, has largely ignored the rule altogether, districts such as the San Joaquin Valley Air Pollution Control District, Ventura County, and Santa Barbara County have all stepped up inspections and have all issued violations for tank emissions. The South Coast Air Quality Management District has taken a leadership position, utilizing existing local rule 1148.1 to require operators to install EVAP 4-3

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[1] https://www.fractracker.org/2022/08/fractracker-finds-widespread-hydrocarbon-emissions-from-active-idle-oil-and-gas-wells-and-infrastructure-in-california/

[2] https://biologicaldiversity.org/w/news/press-releases/epa-rejects-air-pollution-permits-for-oil-gas-wells-in-colorado-2024-02-01/

systems and require the use of CARB-certified combustors to ensure the destruction of methane and other VOCs into carbon dioxide prior to being released into the atmosphere.[3] 4-3 Cont.

Since the implementation of the methane rule, FracTracker has conducted dozens of thermographic inspections of oil and gas facilities in the LA Basin using Forward Looking Infrared (FLIR) optical gas imaging (OGI) cameras. Inspections were completed in collaboration with grassroots organizations by the FracTracker Alliance Western Program Director, a certified thermographer. The installation of EVAP systems and combustors drastically reduced the documented volumes of fugitive emissions, as compared to on-site OGI inspections conducted prior to the installation of combustors. 4-4

While the concentrations and volumes of VOCs emitted from tank venting were vastly reduced, the combustion units themselves were observed to be a new source of methane and VOC releases. The exhaust streams of multiple units had observable concentrations of hydrocarbons.
Example 1: Warren E&P Field
Example 2: Murphy Drill Site
Example 3: Deist Tank Farm
Example 4: Rosecrans Field

Industry and regulators alike often stress the perspective that oil and gas extraction operations can occur in populated areas without degrading the environmental health of communities, if proper engineering protections are in place and best practices followed. Such organizations point to a variety of engineering protections such as EVAP systems and low-NOx burners that, when functioning properly, can prevent leaks from key components of wellhead infrastructure and efficiently combust waste gas. They say that with these engineering standards, hydrocarbons can be extracted from even urban residential environments without harming communities. 4-5

This perspective is patently false. Engineering protections alone are not effective, because oil and gas wellheads are incredibly leak-prone. The many opportunities for large leaks and the combination of many small undetectable leaks provide ample exposure pathways to degrade local and regional air quality with a cocktail of harmful volatile organic compounds. Wellhead infrastructure includes a variety of pipelines, connected by gasketed flanges and valves, all operating under high pressure. Leaks form regularly, and while they are often easily fixed by replacing equipment or just retorquing bolts, they cannot be addressed if they are not identified.

In lieu of eliminating oil and gas extraction operations in communities or requiring all associated gas be collected and refined, FracTracker Alliance urges the South Coast Air District to establish a robust inspection program that increases the oversight of exhaust streams from combustors. In addition to on-site inspections by SCAQMD staff using OGI cameras and methane sniffers, concentrations of methane and VOCs in the inflow and exhaust streams of combustion units should be measured to ensure the units are performing at the maximum possible efficiency. Additionally, these units should be sampled regularly, at least monthly, to ensure the operational efficiency remains within regulatory parameters. 4-6

[3] https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1148-1.pdf

Comment 4-1: Staff recognizes the challenges involved in creating stringent requirements versus verifying compliance with such requirements and appreciates the involvement of grassroot organizations to verify compliance.

Comment 4-2: South Coast AQMD Rule 463 – Organic Liquid Storage applies to most storage tanks and includes requirements for leak detection and repair, domes, seals, and other control equipment. For tanks that are exempt from Rule 463, Rule 1148.1 covers produced gas emissions from smaller tanks located in oil and gas sites.

Comment 4-3: Thank you for your comment.

Comment 4-4: Staff recognizes the effectiveness of using OGI technology in assisting in locating leaks and has therefore proposed implementing the use of such technology in Rule 1148.1 and other rules.

Comment 4-5: Staff is implementing NOx limits and source tests to the combustion equipment that is used on oil and gas sites, such as microturbines and engines that drive wells. Also, staff is implementing the use of OGI technology and notification submission of quantified leaks greater than 25,000 ppmv VOC.

Comment 4-6: Staff is adding a new requirement to PAR 1148.1 that would require oil and gas operators to perform monthly inspections with an optical gas imaging camera. Additionally, for any leaks that are quantified to be greater than 25,000 ppmv VOC the operator will be required to submit a notification.